AR91

# ZARGON ENERGY TRUST 2009 ANNUAL REPORT

# Zargon Energy Trust

Zargon has always been driven by creating value, which has led to solid returns to investors over its 16-year history, first as a corporation, then as an income trust since July 2004. Zargon's business is centred on the acquisition and then exploitation* of low-risk assets; applying technical skills and technologies to increase the recovery of oil and natural gas, usually in well-defined reservoirs. With a large portfolio of exploitation opportunities and undeveloped lands, Zargon is committed to continuing its track record of adding value and driving returns from its asset base.


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*Exploitation: The act of employing to the greatest possible advantage.

# A History of Solid Returns

## Value Creation and Returns

Zargon's commitment to creating value throughout all business cycles has translated into long term returns to its equity holders.

1-year total return **14.6%**

3-year compounded total return **1.0%** PER YEAR

5-year compounded total return **4.7%** PER YEAR

10-year compounded total return **26.3%** PER YEAR

15-year compounded total return **25.3%** PER YEAR

### PERFORMANCE AND STABILITY

Zargon's focus is on stability and consistency over the long term. A commitment to technical excellence and execution in the exploitation of its assets has created a solid track record and a foundation for the future.

#### STABLE DISTRIBUTIONS

Zargon has distributed $0.18 per trust unit per month for the past 52 months as of February 2010, one of the few Canadian oil and gas trusts to maintain stable monthly distributions during the worldwide economic downturn and the recent cycle of low commodity prices.

#### OIL PRODUCTION WEIGHTING

Since Q4 2007, Zargon has focused on oil-weighted acquisitions and exploitation projects and has successfully increased its oil production weighting from 42 percent to 52 percent (6:1 equivalency basis).

#### BALANCE SHEET QUALITY

During the last two years, Zargon has captured accretive property and corporate acquisitions in a down market for equities and asset prices, while maintaining its balance sheet strength.

#### RESERVE QUALITY

Zargon's reserves do not require significant future capital to develop; 87 percent of Zargon's proved and probable reserves are assigned to the proved and probable developed producing category.

#### EXTENDED TAX HORIZON

Zargon has extended its tax-free horizon in preparation for conversion to a corporation at the end of this year. Based on current forward commodity prices, our tax pools help support dividends for at least the next three years.

#### FUTURE DIVIDEND-PAYING COMPANY

As a corporation, Zargon intends to continue to distribute monthly income to investors in the form of a dividend, with the goal of delivering consistent double-digit returns.

# 2009 Highlights

| | 2009 | 2008 | Percent Change |
|---|---|---|---|
| FINANCIAL | | | |
| **Income and Investments** ($ millions) | | | |
| Petroleum and natural gas revenue | **155.99** | 229.49 | (32) |
| Funds flow from operating activities | **86.35** | 106.91 | (19) |
| Cash flows from operating activities | **88.83** | 110.12 | (19) |
| Cash distributions | **45.96** | 39.09 | 18 |
| Net earnings | **2.72** | 68.29 | (96) |
| Net capital expenditures | **104.59** | 119.73 | (13) |
| **Per Unit, Diluted** | | | |
| Funds flow from operating activities ($/unit) | **3.64** | 5.18 | (30) |
| Cash flows from operating activities ($/unit) | **3.74** | 5.34 | (30) |
| Net earnings ($/unit) | **0.13** | 3.80 | (97) |
| **Cash Distributions** ($/trust unit) | **2.16** | 2.16 | – |
| **Balance Sheet at Year End** ($ millions) | | | |
| Property and equipment, net | **425.96** | 386.75 | 10 |
| Bank debt | **76.58** | 77.58 | (2) |
| Unitholders' equity | **248.34** | 222.54 | 12 |
| **Total Units Outstanding at Year End** (millions) | **26.02** | 21.15 | 23 |
| OPERATING | | | |
| **Average Daily Production** | | | |
| Oil and liquids (bbl/d) | **5,055** | 4,306 | 17 |
| Natural gas (mmcf/d) | **28.80** | 29.68 | (3) |
| Equivalent (boe/d) | **9,856** | 9,252 | 7 |
| Equivalent per million trust units (boe/d) | **412** | 446 | (8) |
| **Average Selling Price** (before the impact of financial risk management contracts) | | | |
| Oil and liquids ($/bbl) | **59.89** | 89.65 | (33) |
| Natural gas ($/mcf) | **4.32** | 8.12 | (47) |
| **Proved and Probable Reserves at Year End** | | | |
| Oil and liquids (mmbbl) | **20.07** | 17.81 | 13 |
| Natural gas (bcf) | **73.02** | 71.48 | 2 |
| Equivalent (mmboe) | **32.24** | 29.72 | 8 |
| Equivalent per total unit (boe) | **1.24** | 1.40 | (11) |
| **Wells Drilled, Net** | **25.7** | 35.9 | (28) |
| **Undeveloped Land at Year End** (thousand net acres) | **540** | 419 | 29 |

Notes:

Throughout this report, the calculation of barrels of oil equivalent ("boe") is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil. For a further discussion about this term, refer to the Management's Discussion and Analysis.

For net capital expenditures, amounts include capital expenditures acquired for cash, equity issuances, acquisition costs and net debt assumed on corporate acquisitions.

Funds flow from operating activities is a non-GAAP term that represents net earnings and asset retirement expenditures except for non-cash items. Cash flows from operating activities differ from funds flow from operating activities as a result of changes in non-cash operating working capital. For a further discussion about this term, refer to the Management's Discussion and Analysis.

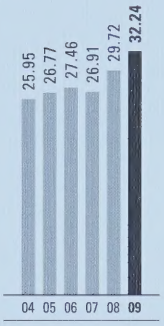
Total units outstanding include trust units plus exchangeable shares outstanding at year end. The exchangeable shares are converted at the exchange ratio at the end of the year.

Average daily production per million trust units is calculated using the weighted average number of units outstanding during the year, plus the weighted average number of exchangeable shares outstanding for the year converted at the average exchange ratio for the year.

# Financial Highlights

- In a year of challenging commodity prices and equity markets:
  - Maintained a stable monthly distribution of $0.18 per unit
  - Maintained a strong balance sheet with a ratio of year end net debt to funds flow from operating activities of 1.0 years
- Funds flow from operating activities totalled $86 million
- Completed and integrated two accretive corporate acquisitions with significant oil exploitation potential
- Completed a June 2009 equity issuance that raised net $33 million from the sale of 2.365 million trust units
- Year end tax pools totalled $293 million, up from $188 million at year end 2008

PROVED AND PROBABLE RESERVES
(mmboe)




Stable cash distributions for over 4 years

$0.18
PER UNIT

Total distributions since becoming a trust in July 2004

$11.66
PER UNIT

2009 funds flow reflects lower commodity prices

$86
MILLION

# Operating Highlights

- Drilled 25.7 net wells with 100 percent success, yielding 15.9 net oil wells and 9.8 net natural gas wells
- Average daily production increased seven percent from 2008 to 9,856 barrels of oil equivalent
- Undeveloped land increased 29 percent to 540 thousand net acres
- Achieved a 67 percent oil-weighted proved and probable finding, development and acquisition cost of $16.45 per barrel of oil equivalent compared with $19.76 in 2008
- Proved and probable reserves increased eight percent from 2008 to 32.24 million barrels of oil equivalent

2009 increase in oil and liquids production

17%

PRODUCTION
(boe/d)

100% drilling success in 2009

25.7
NET WELLS

Net asset value

$21.65
PER UNIT

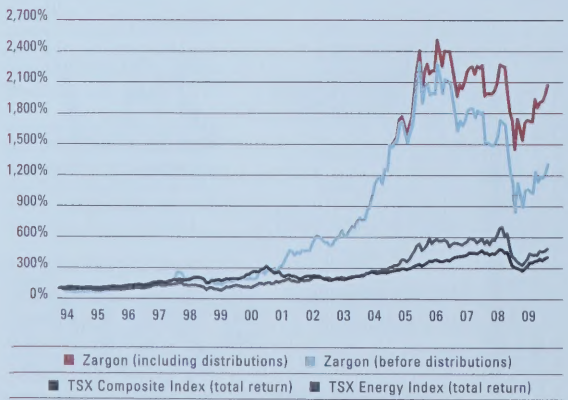
# A Proven Track Record

## Stability

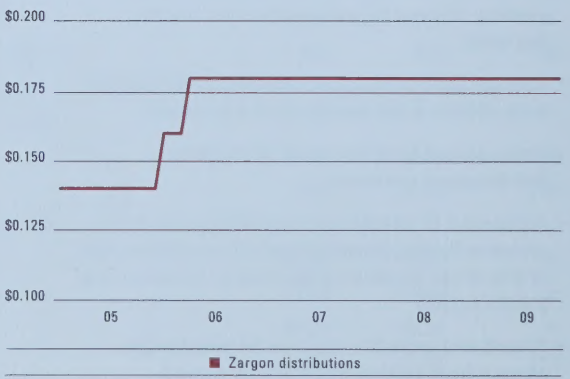
| | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|---|
| Proved and probable (2P) reserves (boe/unit) | **1.24** | 1.40 | 1.36 | 1.41 | 1.41 | 1.39 |
| Average production (boe/d per million units) | **412** | 446 | 436 | 437 | 445 | 447 |
| Average base cash distribution ($/unit/month) | **0.18** | 0.18 | 0.18 | 0.18 | 0.15 | 0.14 |
| Debt to funds flow ratio (years) | **1.0** | 0.8 | 0.8 | 0.5 | 0.3 | 0.4 |
| Net debt ($/unit) | **3.71** | 4.25 | 3.26 | 2.07 | 1.46 | 1.25 |
| Reserve life index (2P) (years) | **8.3** | 8.6 | 8.4 | 9.0 | 8.5 | 8.4 |
| Tax pools ($ millions) | **293** | 188 | 148 | 113 | 90 | 79 |
| Distributions as a percent of funds flow | **53** | 37 | 46 | 43 | 44 | 17 |

## Consistent Returns

TOTAL RETURN vs TSX OIL AND GAS INDEX




ZARGON DISTRIBUTION HISTORY
($/unit/month)



ZARGON PROPERTIES

Our business is exploitation. We use our technical skills to understand the mechanics of individual reservoirs and then apply technologies to increase the recovery of undrained oil or natural gas. These reservoirs are the feedstock for increasing our production and adding reserves. At any time, we are working on a large number of projects, some of which take years to bring into full development. Some of our pools might be considered small by industry standards, but these projects are long term with very attractive economics.

## Oil Exploitation

Oil exploitation is being pursued in all three of our core areas: Williston Basin, Alberta Plains and West Central Alberta. Although each area is geologically and geographically varied, we are pursuing a large number of projects in reservoirs that contain substantial volumes of undrained oil-in-place.

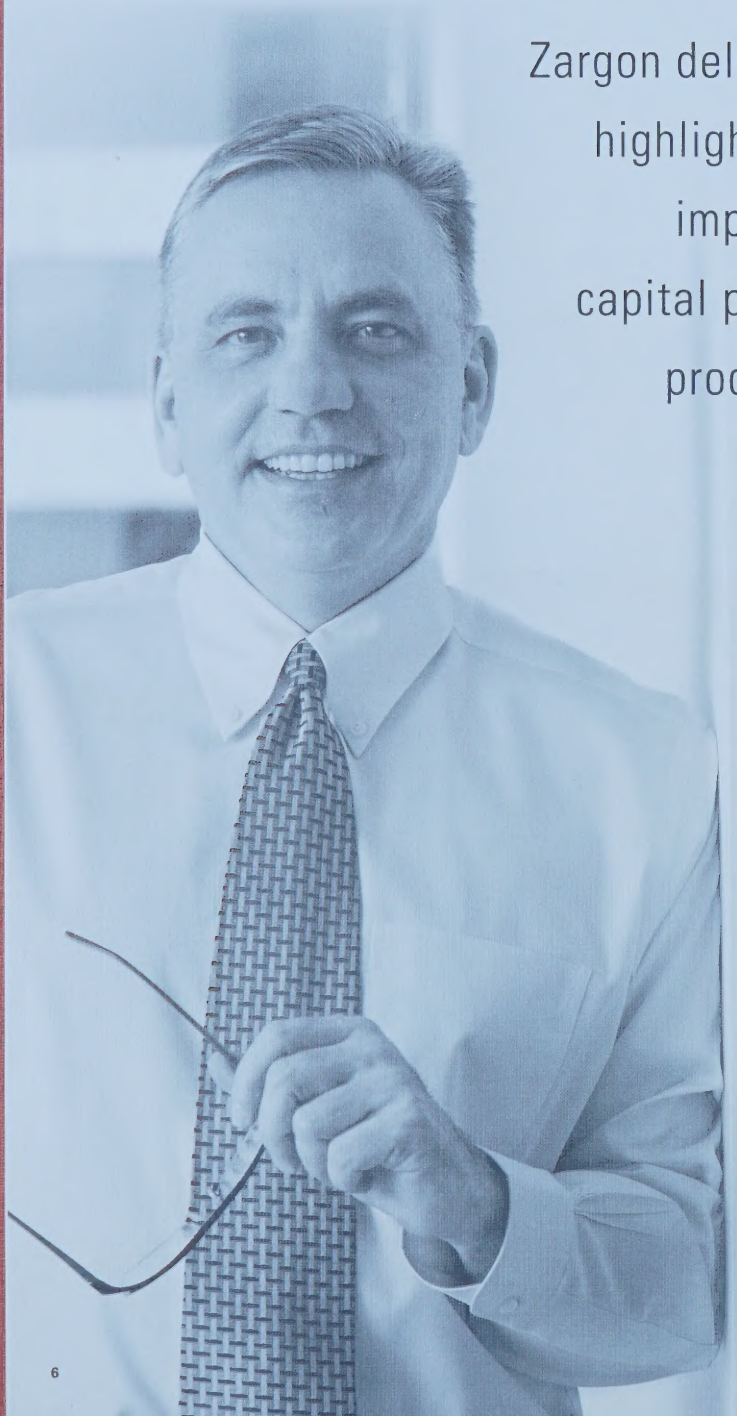
**62%** Proved and probable reserve weighting to oil (6:1 basis)

## Gas Exploitation

Gas exploitation is concentrated in our Alberta Plains and West Central Alberta core areas, where activity tends to focus on value creation from partially depleted gas reservoirs. There are also opportunities across our large undeveloped land base to exploit gas-in-place pools with recent advances in horizontal drilling and fracture stimulation technology.

Net acres of undeveloped land **540** THOUSAND

# President's Message



**TO OUR EQUITY HOLDERS**

Zargon delivered solid results in 2009 highlighted by stable distributions, improved efficiencies from our capital programs and significant oil production and reserve growth.

Craig H. Hansen
President and
Chief Executive Officer

Zargon is well positioned to create significant value through oil and natural gas acquisition and exploitation activities in 2010 and beyond.

During the year, we also completed a public equity issuance and successfully integrated two accretive corporate acquisitions, Masters Energy Inc. ("Masters") and Churchill Energy Inc. ("Churchill"), both with significant oil exploitation potential. All of these accomplishments were achieved despite a very challenging commodity price environment.

## 2009 IN BRIEF

2009 was another year of intense commodity price volatility, which saw extreme price lows for oil in the first quarter and then natural gas in the third quarter. As a result, funds flow from operating activities declined 19 percent to $86 million, or $3.64 per diluted trust unit. However, we were able to withstand these challenges by drawing on our historically conservative balance sheet and forward hedge programs to deliver stable distributions. The Trust maintained its monthly cash distribution at $0.18 per trust unit, a level that has been consistent for the past 52 months as of February 2010. In 2009, Zargon distributed $46 million to unitholders, which equated to a 53 percent payout ratio of our funds flow.

Zargon has generated returns by focusing on our core competency of exploitation of conventional assets.

The Trust also demonstrated growth in oil production and reserves through a successful oil-focused $47 million field capital program and the acquisition of $57 million of properties, primarily consisting of two well-timed accretive corporate acquisitions. These activities were funded by funds flow and $65 million of equity issued in the Masters and Churchill acquisitions, as well as through a June equity public offering.

For the second year in a row, we continued to improve our capital efficiencies and delivered a total proved and probable finding, development and acquisition cost (including future development capital and excluding future Alberta drilling credits) of $16.45 per barrel of oil equivalent, a strong result considering that our reserve additions were 67 percent oil-weighted. All of these accomplishments were made without a significant increase in bank debt, thereby keeping Zargon in a strong financial position and well positioned for the upcoming year of opportunity.

Although the year brought lower revenues, funds flow and earnings, 2009 was a very good year for Zargon from many perspectives. Over our long history, Zargon has generated returns by focusing on our core competency of exploitation of conventional assets; understanding how to increase recoveries of oil and natural gas in typically well-defined reservoirs. That focus allows us to invest capital, in a careful manner, to capture incremental recoveries and add value to our conventional assets. The difficult industry conditions enabled us to reshape our business plan and revitalize our oil and natural gas exploitation business. Working in a weaker industry employment environment, we made good progress in developing the organization's technical capabilities, allowing our people to focus on the efficient execution of projects that can have a bottom line impact.

In addition, the successful integration of our two accretive corporate acquisitions assisted with our tax position in preparation for our upcoming conversion to a corporate entity and brought long term oil exploitation opportunities. On the basis of our 2009 performance, we have entered 2010 in the enviable position of having a promising inventory of exploitation opportunities, which can be funded from our strong balance sheet with over $100 million of unutilized bank lines.

## 2010 AND BEYOND

As we enter 2010, commodity prices have improved substantially from their cyclical lows, and equity and credit markets have improved materially from the difficult times of last spring. Despite these improved conditions and our long term positive commodity pricing outlook, we note with caution the volatility of the trends and we will continue to structure our business to withstand prolonged periods of reduced commodity prices and/or renewed challenges in the equity or credit markets.

In 2010, we anticipate completing additional corporate and/or property acquisitions as the economic climate over the past two years has restricted capital access for some of our peers, which in turn has significantly improved corporate and

We are excited about becoming a dividend-paying corporation at the end of this year, a structure that will continue to permit us to execute our business strategy focused on returns and efficiencies.

property acquisition metrics. This trend has been further amplified by the development of new technology, which has enabled the development of new large-scale resource plays that have attracted capital and attention away from the conventional businesses. Our acquisitions will be focused on conventional assets with significant oil-in-place or gas-in-place that we can exploit using our technical skills and the new enabling technologies related to enhanced oil recoveries and the production of previously inaccessible oil or natural gas in tight conventional reservoirs.

For Zargon, our 2010 field capital programs will continue to focus on the Williston Basin and Alberta Plains core areas, where 2009 horizontal oil exploitation drilling provided strong recycle ratios and returns. For natural gas, we will continue to defer capital expenditures that only accelerate production. We will, however, concentrate on foundation natural gas capital expenditures that set up larger scope and longer term opportunities that can provide strong returns in the context of the current long term forward natural gas prices. With our continued strong financial position and our now expanded feedstock of opportunities coming from recent and anticipated acquisitions, Zargon is well positioned to create significant value through oil and natural gas acquisition and exploitation activities in 2010 and beyond.

Looking beyond the end of this year, when the Canadian income trust era is concluded, Zargon plans to convert to a corporation and continue to deliver monthly income, in the form of dividends, at a targeted 35 percent of funds flow under a stable dividend policy. We continue to believe that this partial cash flow distributing model is an effective model to produce conventional oil and natural gas assets in our relatively mature sedimentary basins, as the commitment to deliver regular dividends provides the economic tension that encourages efficient capital programs.

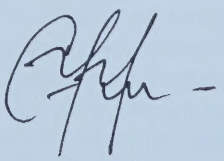
Zargon plans to convert to a corporation and continue to deliver monthly income and modest growth.

We do note that in our post trust structure, our dividends will not provide Zargon the tax shelter that we previously enjoyed with trust distributions. In preparation for our post trust period, we have grown our Canadian income tax sheltering tax pools by a factor of almost four in the last five years. The combination of these increased tax pools and the increase in our capital programs, permitted by a reduction of the target dividend to 35 percent of funds flow from our historical 50 percent target, allows us to extend our tax-free horizon (using current forward commodity prices) into 2014.

In conclusion, although significantly improved from 2009, the upcoming year could very well be another year of volatility and change for our industry. At Zargon, we look forward to 2010 with confidence as we believe we are well prepared to build on the exploitable assets we have acquired and the organizational momentum we have gained in the previous two years. We are excited about becoming a dividend-paying corporation at the end of this year, a structure that will continue to permit us to execute our business strategy focused on returns and efficiencies, which has proven successful over our 16-year public history.

## ACKNOWLEDGEMENTS

We are thankful for the commitment, skill and support of our staff and our Board as we continue to strive to efficiently execute our oil and natural gas business in order to enhance the long term value of Zargon. Finally, on behalf of all employees and our Board, I would like to express our appreciation to our equity holders for their confidence and support for our unwavering commitment to value creation.



C.H. Hansen
President and Chief Executive Officer
March 9, 2010

## ZARGON'S MANAGEMENT TEAM (left to right)

JASON B. DRANCHUK
Vice President, Finance and Controller

HENRY J. BAIRD
Vice President, Reservoir Engineering

AL D. THORSEN
Vice President, Operations

KEVIN C.Y. LEE
Vice President, Alberta Plains North

BRENT C. HEAGY
Executive Vice President
and Chief Financial Officer

MARK I. LAKE
Vice President, Geosciences
and West Central Alberta

CRAIG H. HANSEN
President and
Chief Executive Officer

TRACY L. HOWARD
Corporate Secretary

DANIEL A. ROULSTON
Vice President, Engineering
and Williston Basin

BRIAN G. KERGAN
Vice President, Corporate
Development and Alberta
Plains South

LORNE D. SCHWETZ
Vice President, Land

# Questions and Answers

## Q What is our plan for the post 2010 trust period?

Zargon plans on converting back into a corporation in late 2010. This conversion will entail a tax-free conversion of both trust units and exchangeable shares into common shares of the new corporation.

- Our goal will be to deliver stable or growing dividends based on a target of approximately 35 percent of funds flow from operating activities, down from the current 50 percent trust distribution policy.
- The impact of this reduction on unitholder trust distributions will be partially offset by:
  - improved dividend tax benefits for Canadian taxable shareholders
  - our expectation of modest growth in reserves and production per share coming from increased capital programs.

## Q Why have we chosen to pay dividends in the new corporate structure?

From our perspective, a partial funds flow distributing model implicitly encourages efficiencies in our capital programs.

- We operate in a mature basin and our exploitation business is focused on driving value from our assets, which has served Zargon and our equity holders well, as evidenced by our past performance and returns.
- Over the long term, we believe we can deliver compounded returns that will be attractive to equity markets, which in turn will support our efforts to issue equity at advantageous costs for further expansion.

## Q What about our post 2010 corporate taxes?

As a corporation, Zargon will not be able to create Canadian tax shelter through distributions to our equity holders.

- By moving our dividend target rate to approximately 35 percent of funds flow from operating activities, additional funds will be available to spend on capital projects that will increase tax sheltering benefits for the corporation.
- We will continue to seek acquisitions to increase our tax pools, similar to our series of corporate acquisitions that helped generate a four-fold increase in tax pools in the last five years.
- Based on the current forward commodity prices, our models suggest that we will not be taxable until 2014.

## Q What are our performance targets?

As a corporation, Zargon will seek to deliver annual double-digit compounding returns.

- Our target is a stable or growing dividend stream funded from approximately 35 percent of funds flow from operating activities.
- The funds available for dividends will be augmented by modest production and reserve growth on a per share basis.
- Our growth targets must be debt adjusted and cannot come with the deterioration of the quality or character of our assets.
- To meet these targets we will continue to focus on improving our finding, development and acquisition costs, production addition costs and the related recycle ratios that drive our long term returns.

## Q What are our core competencies?

Over the last two years, we have sharpened our focus on key business drivers, on acquisitions and on the exploitation of our conventional reservoirs.

- Acquisitions – We have added significant exploitation opportunities through small corporate or specific property acquisitions. Key drivers: a strong balance sheet and a disciplined approach in expanding our project portfolio and our asset base.
- Oil Exploitation – Zargon's expertise and experience centres on the application of reservoir engineering technology to increase recovery factors in existing conventional pools. Key drivers: Zargon's large oil-in-place in existing operated pools and a depth of experience in reservoir engineering and project execution.
- Gas Exploitation – Our technical team is focused on implementing the evolving stimulation technologies that release commercial production from conventional tight gas reservoirs with poor recovery factors. Key drivers: our existing developed producing reservoirs, plus undeveloped tight gas accumulations on our 540 thousand net acres of undeveloped land.

## Q What is our acquisition strategy?

Overall, we are aware of the industry environment and are confident enough to be patient. We only acquire assets that meet our economic metrics and provide upside where we can add value.

- Weaker commodity prices and volatile capital markets are resulting in mergers and sales of smaller public and private oil and natural gas entities holding conventional assets. Also, with advances in fracture stimulation technology, the industry has shifted to natural gas and oil resource plays.
- Many competitors are shedding conventional assets for strategic reasons. Although some of the assets have good exploitation potential, they tend to be too small to attract the attention of larger companies or the investment community.

This creates opportunities:

- Zargon is the proper size and has the appropriate technical and operating skills to capitalize on conventional assets with exploitation opportunities.
- Over the last two years, we have completed and successfully integrated four oil exploitation focused corporate acquisitions:
  - Rival Energy Ltd. (public TSX) closed January 2008. (Bellshill Lake oil exploitation)
  - Newpact Energy Corp. (private) closed May 2008. (St. Anne oil exploitation)
  - Masters Energy Inc. (public TSX) closed April 2009. (Little Bow oil exploitation)
  - Churchill Energy Inc. (public TSX) closed September 2009. (Brazeau and Grand Forks oil exploitation)
- We will continue to seek smaller corporate acquisitions that bring quality oil-in-place or gas-in-place projects we can exploit.

## Q What are our oil exploitation competitive advantages?

Zargon is well positioned to work the oil exploitation business in the Western Canadian and Williston sedimentary basins.

- A key advantage is the depth of our technical skills in the prediction of oil, natural gas and water fluid movement within reservoirs, a core competency for Zargon.
- We have lengthy experience in increasing recovery factors from existing oil pools through primary and secondary (waterflood) projects. Now, our larger tertiary (Alkaline Surfactant Polymer – "ASP") project at Little Bow provides Zargon with additional scale and scope.
- We operate in an arena with little competition. We target smaller pools with 4 to 40 million barrels of oil-in-place and 300 to 1,000 barrels of oil per day production increments, which tend to be overlooked by our larger competitors.
- Exploitation projects can require long lead times to implement, but they are well suited to Zargon's patient and long term value perspective.

## Q Can we develop a natural gas exploitation competitive advantage?

By far, the most important recent development in the natural gas industry is the "game changing" introduction of horizontal well fracturing technology.

- Recent technical advances now enable commercial production from tight (low-permeability) or very tight resource reservoirs through the delivery of multiple fracture stimulations in horizontal wells.
- This technology is equally applicable to the exploitation of tighter and smaller conventional reservoirs with significant undrained gas-in-place. Zargon's conventional asset base holds considerable potential for this new technology in:
  - Alberta Plains gas-bearing Viking and mid-Mannville channel sandstones
  - Peace River Arch gas-bearing Montney and Doig sandstones
  - Numerous other opportunities across our 540 thousand net acre undeveloped land base.

## Q Is my investment in Zargon safe?

Ultimately, our most important consideration is the protection of our equity holders' existing capital. We have fiscally conservative policies, as evidenced by our track record of distributions, current balance sheet and hedging policies.

- Conservative banking arrangements (December 31, 2009)
  - 1.0 years net debt to 2009 funds flow from operating activities ratio
  - More than $100 million available on $180 million of banking facilities.
- Conservative distribution policy
  - Distributed only 53 percent of funds flow from operating activities in 2009.
- Active hedging program
  - To protect our forecast funds flow, Zargon maintains an active hedging program. At the date of this report, Zargon has hedged approximately 40 and 20 percent of our forecast 2010 and 2011 oil production, respectively, at average prices in excess of US$78 per barrel.

# Oil Exploitation

To drive value from our oil assets, we pursue three types of exploitation: primary, secondary and, more recently, tertiary recovery projects.

We use our technical skills to employ traditional and new technologies to increase oil recovery.

## OIL EXPLOITATION

To drive value from our oil assets, we pursue three types of exploitation: primary, secondary and, more recently, tertiary recovery projects. All three demand intricate reservoir evaluations and very specific and detailed exploitation plans.

## PRIMARY RECOVERY PROJECTS

Primary oil recovery projects are defined as projects where oil can be produced from a number of natural mechanisms such as reservoir gas expansion or pressure support from an underlying aquifer. The reservoirs that we work on tend to be only partially developed due to lower permeability rock, poorly defined boundaries of a pool or, in some cases, simply inefficient pool development. We use our technical skills to employ traditional and new technologies to increase oil recovery factors in these reservoirs. Typically, our primary recovery projects are developed with vertical wells or horizontal wells, which sometimes require fracture stimulation to initiate production. In some cases, we simply upgrade pumping equipment or fluid handling and treating facilities. As each of our projects tends to contain only 4 to 20 million barrels of oil-in-place (as recognized by the regulatory authorities), they are often overlooked by larger competitors. Still, the project economics can be very attractive.

For the primary projects, we use three dimensional ("3D") seismic, detailed geological studies, reservoir engineering and historical vertical well drilling data to identify and characterize our oil reservoirs.

## PRIMARY RECOVERY PROJECTS

| Core Area | Project | Formation | Drilling Program |
|---|---|---|---|
| [illegible] | Taber South, AB | Sunburst (Mannville A) | Horizontals |
| | Taber South, AB | Sunburst (Glauconite C) | Horizontals |
| | Provost, AB | Dina | Seismic and verticals |
| | Bellshill Lake, AB | Dina | Verticals |
| | Hamilton Lake, AB | Viking | Stimulated horizontals |
| [illegible] | Highvale South, AB | Banff | Seismic and verticals |
| | St. Anne, AB | Banff | Verticals |
| [illegible] | Steelman, SK | Frobisher | Horizontals |
| | Manor, SK | Alida/Tilston | Horizontals |
| | Fertile, SK | Torquay/Bakken | Stimulated horizontals |
| | Elswick, SK | Midale | Horizontals |
| | Cromer, MB | Torquay/Bakken | Stimulated horizontals |
| | Virden, MB | Lodgepole | Horizontals |
| | Daly, MB | Lodgepole | Stimulated horizontals |
| | Mackobee Coulee, ND | Frobisher Equivalent | Seismic and horizontals |

Although ASP tertiary floods are relatively new technology and time consuming to implement, we believe that ASP technology has a very significant upside for southern Alberta's high-permeability, medium-gravity Mannville reservoirs.

## SECONDARY (WATERFLOOD) RECOVERY PROJECTS

Secondary oil recovery projects, also known as waterfloods, rely on the injection of water to increase pressure in a reservoir in order to improve production rates and recovery of the oil-in-place. In some cases, we are working on larger, mature assets where we use our technical background to modify an existing waterflood. On the other hand, we are also working on partially developed pools with lower permeability rock or poorly defined boundaries where waterfloods have not been attempted.

Waterflood projects can have a lengthy start-up as working and royalty interests might need to be negotiated, and regulatory applications must be prepared and submitted prior to construction or modification of field facilities to permit water injection. Once water injection commences, it can take years for the reservoir to repressure and to realize improved production rates. Our waterflood projects tend to have a larger amount of oil-in-place than our primary projects, ranging from 4 to 40 million barrels of oil-in-place (as recognized by the regulatory authorities). While these pools are small on the industry scale, the project economics can be very attractive. As with our primary projects, we find that these smaller scale and longer term projects can be overlooked by larger competitors or our less patient peers.

For our waterflood projects, we use the same evaluation techniques as our primary recovery projects: 3D seismic, detailed geological studies, reservoir engineering and vertical well control. Typically, once water injection has restored reservoir pressures, we accelerate production with the drilling of horizontal or vertical drainage wells.

## SECONDARY (WATERFLOOD) RECOVERY PROJECTS

| Core Area | Project | Formation | Waterflood Action Plan |
|---|---|---|---|
| | Taber South, AB | Sunburst (Mannville A) | Initiate |
| | Taber South, AB | Glauconite (Mannville D) | Modify and drill horizontals |
| | Grand Forks, AB | Glauconite/Sawtooth | Initiate and drill verticals |
| | Hamilton Lake, AB | Viking | Reactivate and drill verticals |
| | Carrot Creek, AB | Cardium | Modify and drill horizontals |
| | Spirit River, AB | Gething | Initiate |
| | Brazeau, AB | Nisku | Accelerate and drill verticals |
| | Steelman, SK | Midale | Modify and drill horizontals |
| | Steelman West, SK | Midale | Initiate and drill horizontals |
| | Steelman, SK | Frobisher Marker | Initiate and drill horizontals |
| | Pinto, SK | Midale | Drill horizontals |
| | Elswick, SK | Midale | Initiate or modify and drill horizontals |
| | Ralph, SK | Midale | Initiate or modify and drill horizontals |
| | Frys, SK | Tilston | Modify and drill horizontals |
| | Carnduff, SK | Frobisher | Drill horizontals |
| | Haas, ND | Alida Equivalent | Modify and drill horizontals |
| | Truro, ND | Alida Equivalent | Modify and drill horizontals |

## TERTIARY (ENHANCED) RECOVERY PROJECTS

With the addition of the Little Bow property in the 2009 Masters acquisition, we have added a tertiary recovery project to our oil exploitation inventory. Tertiary, or enhanced recovery, is the next phase in recovery techniques after primary and secondary projects and typically involves the injection of specific chemicals to improve oil production and oil recovery factors. At Little Bow, we are seeking to increase the pool's oil recovery factor to 52 percent from the 40 percent currently being achieved under a waterflood. Our working interest gives us ownership of 24 mmbbl of oil-in-place (as recognized by the Alberta ERCB regulatory authority) in this Glauconite channel sand.

With the Little Bow project, we are working with a chemical injection process known as an Alkaline Surfactant Polymer ("ASP") flood, which can be suitable for high-permeability, medium-gravity sandstone reservoirs. This particular application involves the injection of alkalines and surfactants in a water solution into the reservoir. The technology uses the characteristics of the cleaner-like alkaline caustic agent and the detergent-like surfactant to lower the capillary pressure that impedes the oil droplets from moving through a reservoir. Polymers are added to the mixture to increase the viscosity (thickness) of water and help flush the remaining oil out of the reservoir.

The majority of our Little Bow laboratory core flood and chemical analyses have been completed, along with reservoir simulations that have shown positive results. Later this year, we anticipate completion of our reservoir studies, project design and detailed cost estimates, and we will then proceed to a decision on this $25 million capital project. Assuming project approval, field construction would proceed in 2011, initial injection would commence in early 2012, and peak oil production would be reached in 2014.

Although ASP tertiary floods are relatively new technology and time consuming to implement, we believe that ASP technology has a very significant upside for southern Alberta's high-permeability, medium-gravity, Mannville reservoirs.

# Natural Gas Exploitation

Our natural gas exploitation business is centred on large undrained gas-in-place resources, or on partially depleted existing natural gas reservoirs.

Zargon's conventional asset base holds considerable potential to develop tight (low-permeability) reserves through horizontal well fracturing technology.

## NATURAL GAS EXPLOITATION

Our natural gas exploitation business is centred on large undrained gas-in-place resources, or on partially depleted existing natural gas reservoirs. These exploitation opportunities are found across our undeveloped land base throughout our Alberta Plains and West Central Alberta core areas.

By far, the largest development in the natural gas industry in the last two years has been horizontal well fracturing technology. This development now enables the production of low-permeability ("tight") conventional reservoirs, or very tight resource reservoirs. The delivery of multiple fracture stimulations in horizontal wells is also well suited to the exploitation of tighter partially drained conventional reservoirs with a significant remaining gas-in-place. Although these discrete conventional opportunities do not have the scale being pursued by our larger competitors, the returns using this new technology can be very attractive.

The Alberta Plains core area consists of generally mature natural gas producing properties where Zargon has a high operated working interest and controls the natural gas gathering and processing infrastructure. Many of these reservoirs are only partially depleted and hold significant undrained remaining gas-in-place. The West Central Alberta natural gas properties are less developed and somewhat more disparate in nature, but provide numerous poorly drained gas-in-place reservoirs that may be suited to the application of new stimulation technology.

In addition, Zargon holds 229 and 250 thousand net acres of undeveloped lands in the Alberta Plains and West Central Alberta core areas, respectively. These lands provide Zargon significant option value related to the application of the new stimulation technologies onto gas-in-place opportunities.

Over the next year, we will continue the necessary expenditures to evaluate the natural gas exploitation potential of our lands and our partially depleted reservoirs.

## NATURAL GAS EXPLOITATION PROJECTS

| Core Area | Project | Formation | Description |
|---|---|---|---|
| [illegible] ns | Jarrow, AB | Viking | Regional gas-charged sands |
| | Jarrow, AB | Mannville | Material balance defined gas-in-place |
| | Jarrow, AB | Mid-Mannville lithic channels | Seismically discrete gas-charged sands |
| | Hamilton Lake, AB | Viking | Regional gas-charged sands |
| [illegible] | Kakut, AB | Doig | Conclude development of 2007–08 discovery |
| | Rycroft, Webster, Spirit River, AB | Doig, Montney, Bluesky | Tight gas-charged sands |
| | Northeast Peace River Arch, AB | Montney | Regional gas-charged Montney subcrop |
| | Highvale, AB | Belly River | Material balance defined gas-in-place |
| | Pembina, AB | Edmonton | Regionally charged low pressure sands |

# Core Area Summaries

| | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|---|
| **Average Production** | | | | | | |
| Oil and liquids (bbl/d) | **1,852** | 1,255 | 563 | 520 | 553 | 595 |
| Natural gas (mmcf/d) | **16.56** | 19.35 | 20.09 | 19.29 | 19.38 | 19.02 |
| Equivalents (boe/d) | **4,614** | 4,480 | 3,911 | 3,736 | 3,783 | 3,765 |
| **Total Proved & Probable Reserves**[1] | | | | | | |
| Oil and liquids (mbbl) | **6,063** | 4,076 | 2,321 | 2,079 | 1,962 | 1,932 |
| Natural gas (bcf) | **42.54** | 44.64 | 44.67 | 46.44 | 46.00 | 46.57 |
| Equivalents (mboe) | **13,152** | 11,517 | 9,766 | 9,818 | 9,625 | 9,694 |
| **Undeveloped Lands** | | | | | | |
| Net acres (thousands) | **229.3** | 197.1 | 128.3 | 120.5 | 120.5 | 146.0 |
| **Drilling Activities** | | | | | | |
| Net wells | **12.0** | 21.8 | 32.1 | 39.5 | 25.1 | 21.4 |
| **Core Area Cash Flow** ($ millions)[2] | **35.69** | 60.88 | 34.87 | 38.23 | 45.68 | 32.71 |
| **Capital Expenditures** ($ millions) | | | | | | |
| Net property and corporate acquisitions | **45.31** | 43.02 | 0.48 | 0.79 | 0.03 | 0.60 |
| Undeveloped land, seismic and geological | **4.76** | 6.55 | 5.58 | 3.12 | 2.41 | 3.09 |
| Drilling and completions | **6.56** | 9.97 | 14.44 | 12.88 | 11.08 | 7.66 |
| Equipping and facilities | **6.97** | 6.45 | 9.83 | 6.16 | 5.55 | 3.22 |
| Total expenditures | **63.60** | 65.99 | 30.33 | 22.95 | 19.07 | 14.57 |
| **Capital Program Efficiencies** | | | | | | |
| Finding, development and acquisition costs ($/boe)[3] | **17.97** | 20.55 | 23.80 | 18.03 | 14.36 | 7.56 |

*(1) Proved and probable reserves are trust working interest reserves before royalties (6:1).*

*(2) The term "core area cash flow" is defined as petroleum and natural gas revenue for a core area, net of royalties and production expenses. The term "funds flow from operating activities" is defined in the Management's Discussion and Analysis. The difference between the summation of the core area cash flows and the funds flow from operating activities is comprised of the corporate charges including general and administrative expenses, interest and financing charges, realized risk management gains/losses, corporate taxes and site restoration costs incurred.*

*(3) The reported proved and probable finding, development and acquisition ("FD&A") costs include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions.*

With its 2009 oil focused acquisition and field capital program, Zargon increased the Alberta Plains core area oil production by 48 percent to 1,852 barrels of oil per day.

## ALBERTA PLAINS

The Alberta Plains core area is located in the east central and southeastern regions of Alberta and is characterized by relatively shallow wells and all-season surface access. This core area brings a large undeveloped land base of 229 thousand net acres. In 2009, Alberta Plains accounted for 58 percent of Zargon's natural gas production and 37 percent of oil production.

Historically, the area has provided significant natural gas operating cash flows from the Jarrow and Hamilton Lake properties. In the past, our large Jarrow and Hamilton Lake undeveloped land inventories provided the feedstock that we successfully explored to maintain production volumes. These same undeveloped lands and partially drained producing reservoirs are now the feedstock for our natural gas exploitation initiatives.

Over the last two years, Zargon has completed four smaller corporate acquisitions, which added exploitation properties at Bellshill Lake, Grand Forks and Little Bow. These new properties, along with our Taber property, offer a significant oil-in-place target for our oil exploitation initiatives.

### 2010 ALBERTA PLAINS KEY INITIATIVES

- Exploit primary recovery oil projects at Taber South, Bellshill Lake, Provost and Hamilton Lake. In particular, continue to develop the Taber South Mannville A pool with horizontal wells and improve reservoir vertical sweep efficiency at Bellshill Lake with vertical wells.
- Exploit secondary recovery oil projects at Taber South, Grand Forks and Hamilton Lake. In particular, rebalance and improve water injection schemes at the Grand Forks Glauconite E pool, the Taber South Mannville D and Glauconite C pools and the Hamilton Lake Viking pool. Subsequent to pool delineation, we plan to design and implement a secondary recovery scheme for the Taber South Mannville A pool.
- Finalize the Little Bow ASP tertiary recovery reservoir studies, project design and detailed cost estimates. Provided project authorization is justified, we will submit regulatory applications and prepare to award the facility construction contracts.
- Conclude the necessary completions, reservoir studies and pilot test expenditures required to evaluate the regional Viking and mid-Mannville channel gas-in-place opportunities at Jarrow and Hamilton Lake.
- Incorporate 3D seismic and material balance analyses to exploit our Jarrow Mannville gas-in-place opportunities.
- Maximize natural gas production volumes at existing properties with production optimizations, recompletions and workovers.

In 2009, Zargon spent $18.29 million of field-related capital in the Alberta Plains core area, which represented 51 percent of the $35.69 million of property cash flow generated by this area. With these expenditures, Zargon drilled 12.0 net wells, which resulted in 7.0 net natural gas wells and 5.0 net oil wells.

This core area's field capital programs were augmented by $45.31 million of capital pertaining to the Masters and Churchill corporate acquisitions, taking the total capital program to $63.60 million, or 178 percent of the core area's cash flow. With this expanded oil-focused capital program, Zargon increased the core area's oil production to 1,852 barrels of oil equivalent per day, a 48 and 229 percent gain over the 2008 and 2007 production volumes, respectively. Similarly, the area's proved and probable oil reserves increased by 49 and 161 percent over 2008 and 2007, respectively, to reach the year end reserves of 6.06 million barrels of oil.

In 2009, we continued to improve capital efficiencies in Alberta Plains by delivering a proved and probable finding, development and acquisition cost of $17.97 per barrel of oil equivalent. In particular, the Masters and Churchill corporate acquisitions and the Taber horizontal drilling program provided large gains in reserves and production.

# Core Area Summaries

| | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|---|
| **Average Production** | | | | | | |
| Oil and liquids (bbl/d) | **396** | 297 | 166 | 168 | 209 | 218 |
| Natural gas (mmcf/d) | **11.70** | 9.86 | 8.94 | 8.19 | 8.25 | 9.56 |
| Equivalents (boe/d) | **2,345** | 1,939 | 1,656 | 1,534 | 1,584 | 1,814 |
| **Total Proved & Probable Reserves**[1] | | | | | | |
| Oil and liquids (mbbl) | **1,496** | 1,237 | 530 | 406 | 455 | 499 |
| Natural gas (bcf) | **28.20** | 24.53 | 20.09 | 20.27 | 21.49 | 22.00 |
| Equivalents (mboe) | **6,196** | 5,326 | 3,879 | 3,785 | 4,036 | 4,166 |
| **Undeveloped Lands** | | | | | | |
| Net acres (thousands) | **250.0** | 159.1 | 164.6 | 202.2 | 197.7 | 184.9 |
| **Drilling Activities** | | | | | | |
| Net wells | **4.1** | 6.7 | 6.2 | 14.7 | 14.1 | 20.6 |
| **Core Area Cash Flow** ($ millions)[2] | **9.31** | 23.40 | 13.70 | 13.41 | 18.57 | 16.16 |
| **Capital Expenditures** ($ millions) | | | | | | |
| Net property and corporate acquisitions/(dispositions) | **11.87** | 22.90 | 0.90 | (0.80) | 0.13 | 0.40 |
| Undeveloped land, seismic and geological | **2.40** | 4.37 | 4.44 | 2.68 | 3.20 | 4.77 |
| Drilling and completions | **3.38** | 8.16 | 7.85 | 11.64 | 9.74 | 14.62 |
| Equipping and facilities | **2.90** | 4.15 | 4.82 | 4.77 | 2.70 | 2.33 |
| Total expenditures | **20.55** | 39.58 | 18.01 | 18.29 | 15.77 | 22.12 |
| **Capital Program Efficiencies** | | | | | | |
| Finding, development and acquisition costs ($/boe)[3] | **12.07** | 19.39 | 23.50 | 59.19 | 38.23 | 40.95 |

*(1) Proved and probable reserves are trust working interest reserves before royalties (6:1).*

*(2) The term "core area cash flow" is defined as petroleum and natural gas revenue for a core area, net of royalties and production expenses. The term "funds flow from operating activities" is defined in the Management's Discussion and Analysis. The difference between the summation of the core area cash flows and the funds flow from operating activities is comprised of the corporate charges including general and administrative expenses, interest and financing charges, realized risk management gains/losses, corporate taxes and site restoration costs incurred.*

*(3) The reported proved and probable finding, development and acquisition ("FD&A") costs include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions.*

In 2009, Zargon was able to continue this core area's capital efficiencies by delivering a proved and probable finding, development and acquisition cost of $12.07 per barrel of oil equivalent.

## WEST CENTRAL ALBERTA

Zargon's West Central Alberta core area is comprised of two producing regions located directly west of the city of Edmonton and on the Peace River Arch. This core area is characterized by a large undeveloped land base of 250 thousand net acres. In 2009, the area accounted for approximately 41 percent of Zargon's natural gas production and eight percent of oil production.

Some of our properties in West Central Alberta have substantial natural gas exploitation potential. In particular, the western acreage on the Peace River Arch has significant gas-charged Montney, Doig and Bluesky sandstones, which may be exploitable through new horizontal well fracture technology. Additionally, the core area's large undeveloped land base and somewhat disparate natural gas properties can be rationalized through trades, acquisitions and sales into a more focused asset.

Although oil production volumes are relatively small, West Central Alberta includes five oil properties, generally located west of Edmonton, which have significant oil-in-place and exploitation potential. Consistent with many of our other assets, these properties hold smaller accumulations of oil-in-place that our exploitation programs target for increased recovery factors.

### 2010 WEST CENTRAL ALBERTA KEY INITIATIVES

- Advance oil exploitation initiatives in the Carrot Creek Cardium, Highvale Banff, Brazeau Nisku, St. Anne Banff and Spirit River Gething projects. Although not large in scope, each of these projects provides the opportunity to deliver very strong returns, production and reserves through the implementation of waterfloods or further horizontal well exploitation.
- Exploit the Doig, Montney and Bluesky natural gas-bearing horizons at the Spirit River, Kakut, Webster and Rycroft horizons on the Peace River Arch area.
- Maximize natural gas production volumes at existing properties with production optimizations, recompletions and workovers. Rationalize disparate natural gas assets through trades, acquisitions and sales.
- Evaluate and maximize the value of the large undeveloped land base acquired in previous exploration initiatives and from four recent corporate acquisitions. Use farm-outs, sales and trades to derive value.

In 2009, Zargon spent $8.68 million of field-related capital in the West Central Alberta core area, which represented 93 percent of the $9.31 million of property cash flow generated by this area. Zargon drilled 4.1 net wells, which resulted in 2.8 net natural gas wells and 1.3 net oil wells.

This core area's field capital programs were augmented by $11.87 million of capital pertaining to the Masters and Churchill corporate acquisitions, taking the total capital program to $20.55 million, or 221 percent of the core area's cash flow. As a result, Zargon increased West Central Alberta production by 21 percent to 2,345 barrels of oil equivalent per day, and proved and probable reserves by 16 percent to 6.20 million barrels of oil equivalent.

In 2009, Zargon was able to continue this core area's capital efficiencies by delivering a proved and probable finding, development and acquisition cost of $12.07 per barrel of oil equivalent. In particular, Doig exploitation gas wells at the Kakut property on the Peace River Arch provided large gains in reserves and production.

# Core Area Summaries

| | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|---|
| **Average Production** | | | | | | |
| Oil and liquids (bbl/d) | **2,807** | 2,754 | 2,946 | 3,117 | 2,935 | 2,603 |
| Natural gas (mmcf/d) | **0.54** | 0.47 | 0.28 | 0.22 | 0.24 | 0.26 |
| Equivalents (boe/d) | **2,897** | 2,833 | 2,993 | 3,152 | 2,975 | 2,643 |
| **Total Proved & Probable Reserves**[1] | | | | | | |
| Oil and liquids (mbbl) | **12,508** | 12,494 | 12,829 | 13,452 | 12,942 | 11,930 |
| Natural gas (bcf) | **2.28** | 2.31 | 2.59 | 2.45 | 1.01 | 0.98 |
| Equivalents (mboe) | **12,889** | 12,878 | 13,262 | 13,861 | 13,110 | 12,093 |
| **Undeveloped Lands** | | | | | | |
| Net acres (thousands) | **60.7** | 62.9 | 68.7 | 58.6 | 48.6 | 45.1 |
| **Drilling Activities** | | | | | | |
| Net wells | **9.6** | 7.4 | 8.6 | 22.0 | 14.3 | 7.5 |
| **Core Area Cash Flow** ($ millions)[2] | **35.83** | 58.05 | 41.57 | 42.55 | 37.12 | 25.37 |
| **Capital Expenditures** ($ millions) | | | | | | |
| Net property and corporate acquisitions/(dispositions) | **0.20** | 0.12 | 0.47 | (3.14) | 2.26 | 10.82 |
| Undeveloped land, seismic and geological | **2.15** | 1.65 | 1.89 | 2.80 | 1.51 | 1.24 |
| Drilling and completions | **12.00** | 9.54 | 10.86 | 17.28 | 12.54 | 4.91 |
| Equipping and facilities | **5.33** | 2.51 | 3.84 | 5.19 | 3.53 | 2.61 |
| Total expenditures | **19.68** | 13.82 | 17.06 | 22.13 | 19.84 | 19.58 |
| **Capital Program Efficiencies** | | | | | | |
| Finding, development and acquisition costs ($/boe)[3] | **18.84** | 16.86 | 38.58 | 15.99 | 8.78 | 11.76 |

*(1) Proved and probable reserves are trust working interest reserves before royalties (6:1)*

*(2) The term "core area cash flow" is defined as petroleum and natural gas revenue for a core area, net of royalties and production expenses. The term "funds flow from operating activities" is defined in the Management's Discussion and Analysis. The difference between the summation of the core area cash flows and the funds flow from operating activities is comprised of the corporate charges including general and administrative expenses, interest and financing charges, realized risk management gains/losses, corporate taxes and site restoration costs incurred.*

*(3) The reported proved and probable finding, development and acquisition ("FD&A") costs include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions.*

The Williston Basin core area posted another good year of capital efficiencies in 2009 as evidenced by a proved and probable finding, development and acquisition cost of $18.84 per barrel of oil equivalent and a core area recycle ratio of 1.9 times.

## WILLISTON BASIN

The Williston Basin core area is characterized by a stable oil production base and significant long term oil exploitation opportunities. The Williston Basin properties are located within relatively close proximity in southeast Saskatchewan, southwest Manitoba and three northern counties of North Dakota. The properties produce light and medium-gravity oil from carbonate reservoirs at depths up to 1,600 metres. In 2009, the Williston Basin contributed 55 percent of the Trust's oil and liquids production and accounted for 62 percent of the Trust's proved and probable oil and liquids reserves.

The majority of Zargon's Williston Basin producing reservoirs are characterized by low to moderate permeability and large volumes of remaining oil-in-place. Through exploitation projects, Zargon seeks to increase oil recovery factors with a combination of exploitation techniques, including: pressure maintenance by water injection, 3D seismic, unstimulated horizontal wells and fracture-stimulated horizontal wells to unlock additional oil reserves. In general, all of our waterflood initiatives are long term projects that lead to facility modifications and revised injector patterns, which then enable the drilling of very profitable drainage horizontal locations in future years.

### 2010 WILLISTON BASIN KEY INITIATIVES

- Exploit primary recovery oil projects at the Steelman, Manor, Fertile, Elswick, Cromer, Virden, Daly and Mackobee Coulee properties. In particular, we will continue to use unstimulated horizontal wells to develop the Steelman Frobisher ridges, the Manor Tilston/Alida structural highs, the Elswick Midale ridges and the Virden Lodgepole pool extensions.
- The Torquay (Bakken) formation at the Fertile and Cromer properties will be exploited with fracture stimulated horizontal wells.
- A large 3D survey will be undertaken at Mackobee Coulee to set up next year's horizontal drilling program.
- Design and initiate secondary (waterflood) recovery oil projects in the Midale and Frobisher formations at Steelman and Elswick, Saskatchewan.
- Modify and enhance secondary (waterflood) recovery schemes in the Midale, Frobisher and Tilston formations at Steelman, Pinto, Elswick, Ralph, Frys and Carnduff.
- Conclude multi-disciplined reservoir studies to rebalance injections and maximize recoveries from the large Haas and Truro, North Dakota pools.

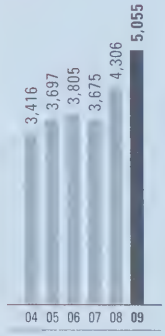
In 2009, Zargon spent $19.48 million of field-related capital in the Williston Basin core area, which represented 54 percent of the $35.83 million of property cash flow generated by this area. With these expenditures, Zargon drilled 9.6 net oil wells with 100 percent success, of which 8.6 net wells were horizontal locations. With this capital program, Zargon maintained production at 2,897 barrels of oil equivalent per day and replaced proved and probable reserves of 12.89 million barrels of oil equivalent.

The Williston Basin core area posted another good year of capital efficiencies in 2009 as evidenced by a proved and probable finding, development and acquisition cost of $18.84 per barrel of oil equivalent and a core area recycle ratio of 1.9 times. In particular, Zargon posted significant new oil production and reserves with the drilling of 7.6 net horizontal wells at the Steelman Frobisher ridge property.

# 2009 – The Year in Review

PRODUCTION
(boe/d)

OIL AND LIQUIDS PRODUCTION
(bbl/d)




NATURAL GAS PRODUCTION
(mmcf/d)

## HIGHLIGHTS

In 2009, Zargon had an active year with value-added acquisitions and improved efficiencies in its capital programs. In what was a challenging year for the oil and gas industry, Zargon was able to take advantage of opportunities to strengthen its business as it heads into its last year as a trust. Zargon is well positioned with strong assets, technical staff and financial position to deliver long term, value-added growth.

| | 2009 | 2008 | Percent Change |
|---|---|---|---|
| Total production (boe/d) | **9,856** | 9,252 | 7 |
| Oil and liquids production (bbl/d) | **5,055** | 4,306 | 17 |
| Natural gas production (mmcf/d) | **28.80** | 29.68 | (3) |
| Wells drilled, net | **25.7** | 35.9 | (28) |
| Total field capital expenditures ($ millions) | **46.45** | 53.35 | (13) |
| Corporate and net property acquisitions ($ millions) | **57.38** | 66.04 | (13) |
| Undeveloped land at year end (thousand net acres) | **540** | 419 | 29 |
| Year end proved and probable reserves (mmboe) | **32.24** | 29.72 | 8 |

## PRODUCTION

Zargon's 2009 average daily production increased seven percent to 9,856 barrels of oil equivalent compared to 9,252 barrels of oil equivalent in 2008 (2007 – 8,560 barrels of oil equivalent per day). Through concerted efforts in the last two years to increase oil volumes through oil-weighted corporate acquisitions and oil exploitation projects, crude oil production increased to 51 percent of total volumes, compared to the 47 and 43 percent weightings in 2008 and 2007, respectively.

Crude oil and natural gas liquid sales volumes increased 17 percent to 5,055 barrels per day from 4,306 barrels per day in 2008 (2007 – 3,675 barrels per day). This increase resulted from the Masters and Churchill acquisitions and successful exploitation of oil properties, primarily in the Williston Basin core area.

Natural gas production volumes decreased three percent in 2009 to average 28.80 million cubic feet per day, compared to 29.68 million cubic feet per day in 2008 (2007 – 29.31 million cubic feet per day). The decrease was primarily due to natural declines and the shut-in of selected high cost properties, offset by production volumes from the acquisitions of Masters and Churchill as well as strong initial production rates at the Kakut property in the West Central Alberta core area.

## FIELD CAPITAL PROGRAM

Reflecting a reduced level of investment in natural gas drilling programs, Zargon drilled 25.7 net wells in 2009, a 28 percent decrease from 2008 and a 45 percent decrease from 2007. The 2009 drilling program resulted in 15.9 net oil wells and 9.8 net natural gas wells with a success ratio of 100 percent.

During 2009, Zargon operated the drilling of 25 gross wells with an average working interest of 98 percent. Minor participation in an additional four non-operated wells brought Zargon's average working interest to 89 percent. The 2009 drilling program continued to focus on crude oil exploitation, particularly in the Williston Basin core area and the Taber property in Alberta Plains.

Expenditures for drilling, completion and workovers totalled $21.94 million, a 21 percent decrease from the $27.66 million spent in 2008. Drilling related expenditures were lower primarily due to Zargon's reduced field activity levels. The 2009 program included the completion of 27.4 net wells, including four non-operated wells. During the year, expenditures for production equipment and facilities, which included oil battery modifications, gas plant expansions, the construction of approximately 20 net kilometres of pipelines and the tie-in of 33.1 net wells, were $15.20 million, a 16 percent increase from the prior year.

PRODUCTION
(boe/d per million trust units)

## 2009 ACQUISITIONS

Zargon continued to take advantage of attractive market values for corporate acquisitions with two accretive transactions, Masters and Churchill.

The Masters acquisition closed on April 29, 2009, for a total transaction value of $40.03 million. The total consideration consisted of the issuance of 1,475,468 Zargon trust units valued at $14.26 per unit, $5.70 million cash and the assumption of $13.29 million of net debt, including acquisition costs. The acquisition of Masters brought production in excess of 1,000 barrels of oil equivalent per day and a significant ASP tertiary oil recovery opportunity at Little Bow in southern Alberta.

The Churchill acquisition closed on September 23, 2009, for a total transaction value of $16.31 million. The consideration consisted of the issuance of 554,669 Zargon trust units valued at $16.87 per unit, $0.11 million in cash and the assumption of net debt of $6.85 million, including acquisition costs. This acquisition added approximately 400 barrels of oil equivalent per day, primarily natural gas, along with significant oil exploitation opportunities, tax pools and undeveloped lands.

Zargon's net property acquisitions totalled $1.04 million, compared to $6.19 million of net property acquisitions in 2008.

DRILLING ACTIVITY
(net wells)

## LAND AND SEISMIC

Zargon spent $5.60 million (including capitalized lease rentals on non-producing properties) to replenish its undeveloped land base. This total was 31 percent lower than the $8.14 million spent in 2008. During the year, Zargon purchased 51 thousand net Crown acres for a total cost of $1.79 million, or $35 per acre. Previously, Zargon acquired 62 thousand net acres in 2008 and 51 thousand net acres in 2007 at average costs of $66 and $82 per acre, respectively.

Zargon's undeveloped land inventory increased 29 percent in 2009 to 540 thousand net acres. This increase resulted from the acquisitions of Masters and Churchill and increased Crown and freehold leasing programs, partially offset by 2009 land expiries. In 2010, Zargon anticipates undeveloped land expiries of approximately 66 thousand net acres, of which a significant percentage will be replenished by Crown and freehold land acquisitions or from corporate acquisitions.

During 2009, Zargon shot 61 kilometres of 2D seismic and 21 square kilometres of 3D seismic. Of this amount, approximately 42 kilometres were shot at the Jarrow property in the Alberta Plains core area, and approximately 16 kilometres at the Antler property in the Williston Basin core area. The 3D seismic program was shot at the Jarrow property in the Alberta Plains core area. Total geological and geophysical costs in 2009 were $3.71 million, 16 percent lower than the prior year's geological and geophysical expenditures of $4.44 million.

UNDEVELOPED LAND
(thousand net acres)

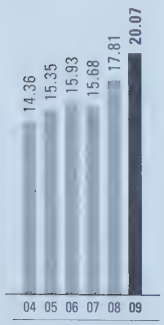
## RESERVES

Since 1993, the independent engineering firm of McDaniel & Associates Consultants Ltd. ("McDaniel") has evaluated 100 percent of Zargon's reserves. Zargon's reserve estimates have been calculated in accordance with National Instrument 51-101 Standards of Disclosure ("NI 51-101") and formal disclosure of Zargon's reserves, as required by NI 51-101, will be included in the Trust's Annual Information Form for the year ended December 31, 2009, which will be filed on SEDAR. Under NI 51-101, proved reserve estimates are defined as having a 90 percent probability that actual reserves recovered over time will equal or exceed proved reserve estimates. Probable reserves are defined under NI 51-101 so that there

PROVED AND PROBABLE RESERVES
(mmboe)

PROVED AND PROBABLE RESERVES
(boe/trust unit)

PROVED AND PROBABLE OIL AND LIQUIDS RESERVES
(mmbbl)




are equal (50 percent) probabilities that the actual reserves to be recovered will be less than, or greater than, the proved and probable reserves estimate. Significant highlights from the 2009 reserves evaluation are as follows:

## Trust Reserves [1]

| At December 31, 2009 | Oil and Liquids (mmbbl) | Natural Gas (bcf) | Equivalents [2] (mmboe) |
|---|---|---|---|
| Proved producing | 14.28 | 42.66 | 21.39 |
| Proved non-producing | 0.18 | 5.26 | 1.06 |
| Proved undeveloped | 0.23 | 0.32 | 0.28 |
| **Total proved** | **14.69** | **48.24** | **22.73** |
| Probable additional producing | 4.49 | 13.78 | 6.79 |
| Probable additional non-producing and undeveloped | 0.89 | 11.00 | 2.72 |
| **Total proved and probable** | **20.07** | **73.02** | **32.24** |
| Proved producing reserve life index, years [3] | 7.1 | 3.8 | 5.5 |
| Proved reserve life index, years [3] | 7.3 | 4.3 | 5.9 |
| Proved and probable reserve life index, years [3] | 10.0 | 6.5 | 8.3 |

*(1) Trust working interest reserves before royalties, boe (6:1), based on the February 23, 2010, McDaniel reserves estimates based on forecast prices and costs as of January 1, 2010.*

*(2) Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

*(3) Calculated based on the amount for the relevant reserves category divided by production for the fourth quarter of 2009 annualized for an entire year.*

In McDaniel's report, proved producing reserves represent 94 percent (2008 – 93 percent) of Zargon's total proved reserves, while total proved reserves account for 71 percent (2008 – 71 percent) of proved and probable reserves. Zargon's proved non-producing reserves are comprised primarily of natural gas reserves at the Alberta Plains property of Jarrow and selected West Central Alberta properties. McDaniel forecasts $7.80 million of net future (forecast prices) capital costs (excluding future Alberta drilling credits) to deliver the total proved reserve estimate. Zargon's probable reserves generally reflect incremental waterflood recoveries on producing oil properties and improved gas recoveries for currently producing natural gas wells. McDaniel forecasts $24.34 million of net future (forecast prices) capital costs (excluding future Alberta drilling credits) to deliver the total proved and probable reserves estimate.

## Reserves Reconciliation

| | Oil and Liquids (mmbbl) | | | Natural Gas (bcf) | | | Equivalents (mmboe) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Proved | Probable | Proved & Prob. | Proved | Probable | Proved & Prob. | Proved | Probable | Proved & Prob. |
| **December 31, 2008** | **12.98** | **4.83** | **17.81** | **48.47** | **23.01** | **71.48** | **21.05** | **8.67** | **29.72** |
| Discoveries and extensions | 0.67 | 0.43 | 1.10 | 2.20 | 1.88 | 4.08 | 1.04 | 0.74 | 1.78 |
| Revisions | 0.91 | (0.73) | 0.18 | 3.09 | (3.42) | (0.33) | 1.42 | (1.30) | 0.12 |
| Acquisitions and dispositions | 1.98 | 0.85 | 2.83 | 4.99 | 3.31 | 8.30 | 2.82 | 1.40 | 4.22 |
| Production | (1.85) | – | (1.85) | (10.51) | – | (10.51) | (3.60) | – | (3.60) |
| **December 31, 2009** | **14.69** | **5.38** | **20.07** | **48.24** | **24.78** | **73.02** | **22.73** | **9.51** | **32.24** |

Proved reserves at December 31, 2009, increased eight percent from the prior year. Proved 2009 reserve additions were 5.28 million barrels of oil equivalent (after revisions), or 3.86 million barrels of oil equivalent (before revisions). Positive technical proved reserve revisions were 1.42 million barrels of oil equivalent, or seven percent of the 2009 proved reserves' opening balance. This increase reflects probable reserves being converted to proved reserves through positive results from 2009 capital programs in all core areas.

On a proved and probable basis, Zargon's reserves increased eight percent in 2009. Zargon replaced 170 percent (167 percent before revisions) of 2009 production through the addition of 6.12 million barrels of oil equivalent (after revisions), or 6.00 million barrels of oil equivalent (before revisions). Oil reserves accounted for 67 percent (after revisions) of the proved and probable reserve additions. Field capital exploration and development programs provided 1.78 million barrels of oil equivalent of new additions. The corporate acquisitions of Masters and Churchill and the net property acquisitions for 2009 added 3.12, 1.00 and 0.10 million barrels of oil equivalent, respectively. Positive technical reserve revisions were 0.12 million barrels of oil equivalent. During the year, positive technical revisions pertaining to Williston Basin oil properties and West Central gas properties were offset by reserve adjustments related to negative production performance at Jarrow in the Alberta Plains core area.

PROVED AND PROBABLE NATURAL GAS RESERVES
(bcf)

## FINDING, DEVELOPMENT AND ACQUISITION COSTS

In 2009, Zargon continued to improve efficiencies in its capital programs. Zargon's total proved finding, development and acquisition ("FD&A") costs, taking into account reserve revisions and changes in estimated future development capital, were $19.24 per barrel of oil equivalent. For calculation purposes, the $103.83 million of 2009 net capital additions was combined with a decrease in estimated future development capital (excluding future Alberta drilling credits) for total proved reserves of $2.23 million ($7.80 million at December 31, 2009, compared to $10.03 million at December 31, 2008). If the change in future development costs is excluded, the 2009 proved FD&A costs, taking into account reserve revisions, were $19.66 per barrel of oil equivalent.

Zargon's 2009 proved and probable FD&A costs, taking into account reserve revisions and changes in estimated future development capital, were $16.45 per barrel of oil equivalent. For calculation purposes, the $103.83 million of 2009 net capital additions was combined with a decrease in estimated future development capital (excluding future Alberta drilling credits) for proved and probable reserves of $3.18 million ($24.34 million at December 31, 2009, compared to $27.52 million at December 31, 2008). If the change in future development costs is excluded, the 2009 proved and probable FD&A costs, taking into account reserve revisions, were $16.97 per barrel of oil equivalent.

### Proved and Probable Finding, Development and Acquisition Costs[1]

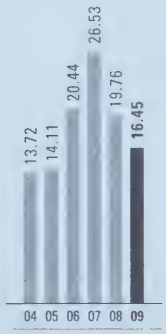
| | **2009** | 2008 | 2007 |
|---|---|---|---|
| Total net capital expenditures ($ millions)[2] | **103.83** | 119.39 | 65.40 |
| Total net capital expenditures plus change in forecast future development costs ($ millions) | **100.65** | 122.49 | 68.19 |
| Proved and probable reserves (mmboe) | | | |
| Open | **29.72** | 26.91 | 27.46 |
| Discoveries and extensions | **1.78** | 2.48 | 2.55 |
| Acquisitions and dispositions | **4.22** | 3.54 | – |
| Revisions | **0.12** | 0.18 | 0.02 |
| Production | **(3.60)** | (3.39) | (3.12) |
| Close | **32.24** | 29.72 | 26.91 |
| Proved and probable FD&A costs ($/boe)[3] | **16.45** | 19.76 | 26.53 |
| Proved and probable three-year FD&A costs ($/boe)[3] | **19.57** | 21.35 | 19.58 |

*(1) The aggregate of the exploration, development and acquisition costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding, development and acquisition costs related to reserves additions for that year.*

*(2) Amounts exclude additions for administrative assets.*

*(3) Amounts are calculated including the change in future development costs.*

PROVED AND PROBABLE FINDING, DEVELOPMENT AND ACQUISITION COSTS
($/boe)



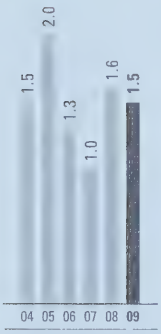
Zargon's improved FD&A costs resulted from the Masters and Churchill corporate acquisitions, which collectively added 4.12 million barrels of oil equivalent proved and probable reserves at an average cost of $14.08 per barrel of oil equivalent (inclusive of future capital, but excluding future Alberta drilling credits). With the ability to execute value-added acquisitions, a primary focus on oil exploitation and an emphasis on improving the execution of tie-ins, completions and other related operating activities, Zargon is well positioned to continue to build efficiencies in its oil and natural gas exploitation business.

In 2009, Zargon's corporate and net property acquisitions were $57.38 million. If the impact of the 2009 corporate and net property acquisitions is excluded, Zargon's proved and probable finding and development ("F&D") costs, including future development costs, would have been $22.77 per barrel of oil equivalent (2008 – $21.22 per barrel of oil equivalent).

### Capital Program Performance

| | 2009 | 2008 | 2007 | Three-Year Average (2007–2009) |
|---|---|---|---|---|
| Trust funds flow from operating activities ($/boe)[1] | **24.01** | 31.57 | 25.55 | 27.02 |
| **Total Capital Program** (excluding future development costs) | | | | |
| Proved and probable FD&A costs ($/boe)[2] | **16.97** | 19.26 | 25.45 | 19.38 |
| Trust recycle ratio[3] | **1.41** | 1.64 | 1.00 | 1.39 |
| **Total Capital Program** (including future development costs) | | | | |
| Proved and probable FD&A costs ($/boe)[2] | **16.45** | 19.76 | 26.53 | 19.57 |
| Trust recycle ratio[3] | **1.46** | 1.60 | 0.96 | 1.38 |

PROVED AND PROBABLE TRUST RECYCLE RATIOS




*(1) Trust funds flow from operating activities including allowances for current taxes, interest and financing charges and general and administrative expenses on a barrel of oil equivalent production basis (6:1).*

*(2) FD&A and F&D costs taking into account reserve revisions during the year on a barrel of oil equivalent basis (6:1).*

*(3) Trust recycle ratio is defined as the Trust funds flow from operating activities per barrel of oil equivalent divided by proved and probable finding, development and acquisition costs per barrel of oil equivalent. In the case of amounts for the capital program exclusive of net acquisitions/dispositions and corporate acquisitions, the Trust funds flow per barrel of oil equivalent is divided by proved and probable finding and development costs.*

## NET ASSET VALUE

Zargon's oil, natural gas liquids and natural gas reserves were evaluated using the McDaniel product price forecasts effective January 1, 2010, prior to provisions for income taxes, interest, debt service charges and general and administrative expenses.

The estimated future net revenue contained in the following table does not necessarily represent the fair market value of the reserves. There is no assurance that the forecast price and cost assumptions contained in the McDaniel reserves evaluation will be attained and variations could be material. The recovery and reserve estimates described herein are estimates only. Actual reserves may be greater or less than those calculated.

### Before Tax Present Value of Future Net Revenue *(Forecast Price Case)*

| | Discount Rate | | | |
|---|---|---|---|---|
| ($ millions) | 0% | 5% | 10% | 15% |
| Proved producing | 700.8 | 526.9 | 425.9 | 361.0 |
| Proved non-producing | 22.0 | 17.3 | 14.1 | 11.7 |
| Proved undeveloped | 7.5 | 4.8 | 3.3 | 2.4 |
| **Total proved** | **730.3** | **549.0** | **443.3** | **375.1** |
| Probable | 373.3 | 217.5 | 149.1 | 112.0 |
| **Total proved and probable** | **1,103.6** | **766.5** | **592.4** | **487.1** |

NET ASSET VALUE
(PVBT 10%)
($/diluted unit)

### Net Asset Value

| As at December 31 ($ millions) | 2009 | 2008 | 2007 |
|---|---|---|---|
| Proved and probable reserves (PVBT 10%)[1][2] | **592.4** | 567.0 | 470.1 |
| Undeveloped land | **58.8** | 70.4 | 43.2 |
| Working capital (excluding unrealized risk management assets/liabilities and future income taxes) | **(11.4)** | (10.1) | (6.9) |
| Bank debt | **(76.6)** | (77.6) | (56.9) |
| Proceeds from the exercise of all trust unit rights | **41.0** | 42.3 | 39.3 |
| Net asset value (including trust unit rights dilution) | **604.2** | 592.0 | 488.8 |
| Net asset value per unit | | | |
| Total ($/unit) | **21.65** | 25.99 | 22.75 |
| With full dilution ($/unit)[3] | **21.77** | 25.96 | 23.00 |

*The preceding table shows what is customarily referred to as a "produce-out" net asset value calculation under which the current value of Zargon's reserves would be produced at the McDaniel forecast future prices and costs. The value is a snapshot in time as of December 31, 2009, and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. In this analysis, the present value of the proved and probable reserves is calculated at a before tax 10 percent discount rate. In the net asset value calculation, Zargon's 540 thousand net acres of undeveloped land is valued at $58.80 million based on the independent firm of Seaton-Jordon & Associates Ltd. valuation of undeveloped lands as at December 31, 2009.*

*(1) McDaniel's estimate of future before tax cash flow discounted at PV 10 percent.*

*(2) PVBT represents present value before taxes.*

*(3) Full dilution of units represents the year end units outstanding plus the presumed exercise of all trust unit rights and the conversion of exchangeable shares converted at the exchange ratio at the end of the year. At December 31, 2009, Zargon had 23.097 million trust units, 1.784 million exchangeable shares and 1.743 million trust unit incentive rights issued and outstanding. Assuming conversion of exchangeable shares at the effective exchange ratio at year end of 1.63709 and the exercise of all trust unit incentive rights, there would be 27.761 million trust units outstanding at this date.*

## FINANCING

Throughout 2009, Zargon maintained a strong financial position with a debt net of working capital (excluding unrealized risk management assets/liabilities and future income taxes) to annualized funds flow from operating activities ratio of 1.0 at December 31, 2009. On June 5, 2009, a bought-deal offering of 2.365 million trust units closed at $15.00 per unit for total gross proceeds of $35.48 million ($33.44 million net of issue costs).

At December 31, 2009, Zargon had approximately $103 million of unutilized committed credit facilities remaining on the $180 million credit facilities held by three major Canadian based banking institutions.

# Six-Year Summary

| FINANCIAL ($ thousands, except per unit amounts) | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|---|
| **Petroleum and natural gas revenue** | **155,985** | 229,494 | 155,512 | 154,039 | 162,722 | 123,968 |
| Less expenses – cash items | | | | | | |
| Royalties | **27,422** | 46,644 | 32,746 | 33,431 | 37,319 | 28,047 |
| Production | **47,564** | 39,913 | 32,620 | 26,416 | 24,035 | 21,692 |
| General and administrative | **13,769** | 10,447 | 8,209 | 6,973 | 6,053 | 4,358 |
| Realized risk management (gain)/loss | **(27,685)** | 15,722 | (4,255) | 569 | 7,754 | 4,568 |
| Interest and financing charges | **3,015** | 4,911 | 3,071 | 1,532 | 786 | 440 |
| Current and capital taxes | **2,492** | 4,051 | 2,143 | 1,598 | 1,801 | 1,114 |
| Asset retirement expenditures | **3,056** | 897 | 1,140 | 627 | 604 | 414 |
| **Funds flow from operating activities** | **86,352** | 106,909 | 79,838 | 82,893 | 84,370 | 63,335 |
| Less expenses – non-cash items | | | | | | |
| Depletion, depreciation and foreign exchange | **64,899** | 57,680 | 48,184 | 41,160 | 37,283 | 26,850 |
| Unrealized risk management (gain)/loss | **36,393** | (44,378) | 16,796 | (9,553) | 3,756 | – |
| Future income tax (recovery) | **(18,947)** | 12,751 | (15,470) | (2,824) | 474 | 9,639 |
| Accretion of asset retirement obligations | **2,744** | 2,183 | 1,406 | 1,244 | 1,196 | 1,076 |
| Unit-based compensation | **1,263** | 1,185 | 1,705 | 1,856 | 902 | 3,682 |
| **Earnings before non-controlling interest** | **3,056** | 78,385 | 28,357 | 51,637 | 41,363 | 22,502 |
| Less non-controlling interest – exchangeable shares | **337** | 10,100 | 3,805 | 7,138 | 5,994 | 1,870 |
| **Net earnings** | **2,719** | 68,285 | 24,552 | 44,499 | 35,369 | 20,632 |
| **Cash flows from operating activities** | **88,828** | 110,124 | 76,303 | 83,735 | 82,969 | 63,354 |
| **Per unit, diluted** | | | | | | |
| Funds flow from operating activities | **3.64** | 5.18 | 4.08 | 4.31 | 4.48 | 3.38 |
| Cash flows from operating activities | **3.74** | 5.34 | 3.90 | 4.35 | 4.40 | 3.38 |
| Net earnings | **0.13** | 3.80 | 1.45 | 2.68 | 2.19 | 1.20 |
| **Net capital expenditures** | **104,593** | 119,733 | 66,669 | 63,366 | 54,684 | 56,273 |
| **Cash distributions** | **45,964** | 39,086 | 36,695 | 35,902 | 37,444 | 10,702 |
| **Cash distributions** ($/trust unit) | **2.16** | 2.16 | 2.16 | 2.16 | 2.32 | 0.70 |
| **Balance sheet at year end** | | | | | | |
| Property and equipment, net | **425,964** | 386,746 | 313,949 | 283,108 | 253,315 | 209,736 |
| Bank debt | **76,580** | 77,581 | 56,868 | 30,037 | 10,339 | 14,230 |
| Unitholders' equity | **248,341** | 222,542 | 161,478 | 165,562 | 144,613 | 120,622 |
| Unitholders' equity ($/total units) | **9.55** | 10.52 | 8.17 | 8.53 | 7.62 | 6.48 |
| **Year end total units outstanding** (thousands) | **26,017** | 21,154 | 19,761 | 19,424 | 18,988 | 18,610 |

| | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|---|
| OPERATING | | | | | | |
| **Total production** (boe/d) | **9,856** | 9,252 | 8,560 | 8,422 | 8,342 | 8,222 |
| Oil and liquids (bbl/d) | **5,055** | 4,306 | 3,675 | 3,805 | 3,697 | 3,416 |
| Natural gas (mmcf/d) | **28.80** | 29.68 | 29.31 | 27.70 | 27.87 | 28.84 |
| Equivalent per million trust units (boe/d) | **412** | 446 | 436 | 437 | 445 | 447 |
| **Total proved reserves** (mboe) | **22,727** | 21,055 | 18,741 | 19,050 | 19,243 | 19,049 |
| Proved oil and liquids (mbbl) | **14,687** | 12,976 | 11,434 | 11,523 | 11,490 | 10,954 |
| Proved natural gas (bcf) | **48.24** | 48.47 | 43.86 | 45.15 | 46.52 | 48.57 |
| **Total proved and probable reserves** (mboe) | **32,237** | 29,721 | 26,908 | 27,464 | 26,771 | 25,955 |
| Proved and probable oil and liquids (mbbl) | **20,067** | 17,807 | 15,683 | 15,937 | 15,354 | 14,361 |
| Proved and probable natural gas (bcf) | **73.02** | 71.48 | 67.36 | 69.15 | 68.50 | 69.56 |
| Equivalent per total unit (boe) | **1.24** | 1.40 | 1.36 | 1.41 | 1.41 | 1.39 |
| **Average selling price before the impact of financial risk management contracts** | | | | | | |
| WTI crude oil price ($US/bbl) | **61.80** | 99.65 | 72.31 | 66.22 | 56.56 | 41.40 |
| Edmonton par crude oil price ($Cdn/bbl) | **65.87** | 102.16 | 76.35 | 72.77 | 68.72 | 52.54 |
| Zargon realized crude oil price ($Cdn/bbl) | **59.89** | 89.65 | 64.71 | 61.25 | 57.15 | 45.37 |
| NYMEX average daily spot natural gas price ($US/mmbtu) | **3.90** | 8.88 | 6.98 | 6.75 | 8.89 | 5.90 |
| AECO average daily spot natural gas price ($Cdn/mmbtu) | **3.96** | 8.16 | 6.45 | 6.54 | 8.77 | 6.55 |
| Zargon realized natural gas price ($Cdn/mcf) | **4.32** | 8.12 | 6.40 | 6.82 | 8.41 | 6.37 |
| **Drilling activity** (number of net wells) | | | | | | |
| Oil | **15.9** | 17.9 | 11.6 | 22.5 | 13.5 | 5.7 |
| Natural gas | **9.8** | 14.5 | 32.7 | 47.7 | 35.3 | 35.4 |
| Water injector | **–** | 0.5 | – | 2.0 | 0.9 | 0.8 |
| Dry | **–** | 3.0 | 2.6 | 4.0 | 3.8 | 7.6 |
| Total | **25.7** | 35.9 | 46.9 | 76.2 | 53.5 | 49.5 |
| Exploratory | **2.3** | 12.6 | 17.7 | 28.8 | 23.0 | 25.9 |
| Development | **23.4** | 23.3 | 29.2 | 47.4 | 30.5 | 23.6 |
| Average Zargon working interest (percent) | **89** | 92 | 89 | 86 | 89 | 83 |
| **Other data** | | | | | | |
| Undeveloped land (thousand net acres) | **540** | 419 | 362 | 381 | 367 | 376 |
| Closing trust unit price ($/unit) | **19.25** | 17.44 | 23.06 | 24.79 | 31.75 | 23.85 |

*Notes:*

*Throughout this report, funds flow from operating activities, funds flow from operating activities per diluted unit and funds flow netbacks are now calculated inclusive of asset retirement expenditures. All prior period calculations have been restated to reflect this change.*

*Throughout this report, the calculation of barrels of oil equivalent ("boe") is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil. For a further discussion about this term, refer to the Management's Discussion and Analysis.*

*Funds flow from operating activities is a non-GAAP term that represents net earnings and asset retirement expenditures except for non-cash items. Cash flows from operating activities differ from funds flow from operating activities as a result of changes in non-cash working capital. For a further discussion about this term, refer to the Management's Discussion and Analysis.*

*For net capital expenditures, amounts include capital expenditures acquired for cash, equity issuances, acquisition costs and net debt assumed on corporate acquisitions.*

*Cash distributions to unitholders commenced subsequent to the reorganization of the Company into a Trust effective July 15, 2004.*

*Total units outstanding include trust units plus exchangeable shares outstanding at year end. The exchangeable shares are converted at the exchange ratio at the end of the year.*

*Average daily production per million trust units is calculated using the weighted average number of units outstanding during the year, plus the weighted average number of exchangeable shares outstanding for the year converted at the average exchange ratio for the year.*

*Certain comparative period numbers reflect retroactive restatement due to a change in accounting policy.*

# CORPORATE INFORMATION

**BOARD OF DIRECTORS**

Craig H. Hansen
*Calgary, Alberta*

K. James Harrison [3] [4]
*Chairman of the Board*
*Oakville, Ontario*

Kyle D. Kitagawa [1] [2]
*Calgary, Alberta*

Geoffrey C. Merritt [2]
*Calgary, Alberta*

Margaret A. McKenzie [1] [3]
*Calgary, Alberta*

Jim Peplinski [2] [4]
*Calgary, Alberta*

J. Graham Weir [1] [2]
*Calgary, Alberta*

Grant A. Zawalsky [3] [4]
*Calgary, Alberta*

**OFFICERS**

Craig H. Hansen
*President and Chief Executive Officer*

Brent C. Heagy
*Executive Vice President and*
*Chief Financial Officer*

Henry J. Baird
*Vice President, Reservoir Engineering*

Jason B. Dranchuk
*Vice President, Finance and Controller*

Tracy L. Howard
*Corporate Secretary*

Brian G. Kergan
*Vice President, Corporate Development and Alberta Plains South*

Mark I. Lake
*Vice President, Geosciences and West Central Alberta*

Kevin C.Y. Lee
*Vice President, Alberta Plains North*

Daniel A. Roulston
*Vice President, Engineering and Williston Basin*

Lorne D. Schwetz
*Vice President, Land*

Al D. Thorsen
*Vice President, Operations*

*(1) Audit Committee*
*(2) Reserves Committee*
*(3) Governance and Nominating Committee*
*(4) Compensation Committee*

**STOCK EXCHANGE LISTING**

Toronto Stock Exchange

Zargon Energy Trust
Trust Units
Trading Symbol: ZAR.UN

Zargon Oil & Gas Ltd.
Exchangeable Shares
Trading Symbol: ZOG.B

**TRANSFER AGENT**

Valiant Trust Company
310, 606 – 4th Street S.W.
Calgary, Alberta T2P 1T1

**BANKERS**

The Toronto Dominion Bank
910, 333 – 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Canadian Imperial Bank of Commerce
9th Floor, Bankers Hall East
855 – 2nd Street S.W.
Calgary, Alberta T2P 2P2

The Bank of Nova Scotia
2000, 700 – 2nd Street S.W.
Calgary, Alberta T2P 2N7

**LEGAL COUNSEL**

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1400, 350 – 7th Avenue S.W.
Calgary, Alberta T2P 3N9

**CONSULTING ENGINEERS**

McDaniel & Associates Consultants Ltd.
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Calgary, Alberta T2P 3G6

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Calgary, Alberta T2P 3B6
Telephone: 403-264-9992
Fax: 403-265-3026
Email: zargon@zargon.ca

**WEBSITE**

www.zargon.ca

## ANNUAL MEETING

The Annual and Special meeting of the Unitholders of Zargon Energy Trust will be held on Wednesday, April 28, 2010, at 3:00 pm (Calgary time) in the Strand/Tivoli Room of the Metropolitan Conference Centre, 333 – 4th Avenue S.W., Calgary, Alberta.

| | |
|---|---|
| **bbl** | Barrel |
| **bbl/d** | Barrels per day |
| **bcf** | Billion cubic feet |
| **boe** | Barrels of oil equivalent (6 mcf is equivalent to 1 bbl) |
| **boe/d** | Barrels of oil equivalent per day |
| **btu** | British thermal units |
| **F&D** | Finding and development |
| **FD&A** | Finding, development and acquisition |
| **gj** | Gigajoule |
| **gj/d** | Gigajoules per day |
| **m** | Thousand |
| **mm** | Million |
| **mmbtu** | Million British thermal units |
| **mcf** | Thousand cubic feet |
| **mcf/d** | Thousand cubic feet per day |
| **PV** | Present value |
| **PVBT** | Present value before tax |

This document offers our assessment of Zargon's future plans and operations as at March 9, 2010, and contains forward-looking statements including:

- our expectations for commodity prices referred to under the heading "President's Message";
- our expectations for our cash distributing structure and cash distributions referred to under the headings "President's Message" and "Questions and Answers";
- our expectations for capital programs, acquisitions and developments referred to under the headings "President's Message", "Questions and Answers", "Oil Exploitation", "Natural Gas Exploitation" and "Core Area Summaries";
- our expectations for corporate size and future production levels referred to under the headings "Questions and Answers" and "Core Area Summaries";
- our expectations for our hedging program referred to under the heading "Questions and Answers";
- our expectations for changes in undeveloped land referred to under the heading "Year in Review";
- our expectations on our conversion to a corporation referred to under the headings "President's Message" and "Questions and Answers";
- our expectations for our tax shelters referred to under the headings "President's Message" and "Questions and Answers".

Such statements are generally identified by the use of words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "plan", "intend", "believe" and similar expressions (including the negatives thereof). By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including such as those relating to results of operations and financial condition, general economic conditions, industry conditions, changes in regulatory and taxation regimes, volatility of commodity prices, escalation of operating and capital costs, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel. Risks are described in more detail in our Annual Information Form, which is available on our website and at www.sedar.com. Forward-looking statements are provided to allow investors to have a greater understanding of our business.

You are cautioned that the assumptions, including among other things, future oil and natural gas prices; future capital expenditure levels; future production levels; future exchange rates; the cost of developing and expanding our assets; our ability to obtain equipment in a timely manner to carry out development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our development and acquisition activities used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. The forward-looking information contained in this document is expressly qualified by this cautionary statement. Our policy for updating forward-looking statements is that Zargon disclaims, except as required by law, any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

ZARGON
ENERGY TRUST

AR91

# ZARGON ENERGY TRUST 2009 FINANCIAL REPORT

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# ABBREVIATIONS

| | |
|---|---|
| **bbl** | Barrel |
| **bbl/d** | Barrels per day |
| **bcf** | Billion cubic feet |
| **boe** | Barrels of oil equivalent (6 mcf is equivalent to 1 bbl) |
| **boe/d** | Barrels of oil equivalent per day |
| **btu** | British thermal units |
| **gj** | Gigajoule |
| **gj/d** | Gigajoules per day |
| **m** | Thousand |
| **mcf** | Thousand cubic feet |
| **mcf/d** | Thousand cubic feet per day |
| **mm** | Million |
| **mmbtu** | Million British thermal units |
| **MWh** | Megawatt hour |
| **MWs/d** | Megawatts per day |
| **AECO** | Alberta gas trading price |
| **AESO** | Alberta Electric Systems Operator |
| **API** | American Petroleum Institute |
| **EIC** | Emerging Issues Committee |
| **LIBOR** | London Interbank Offered Rate |
| **NYMEX** | New York Mercantile Exchange |
| **WTI** | West Texas Intermediate |

# ANNUAL MEETING

The Annual and Special meeting of the Unitholders of Zargon Energy Trust will be held on Wednesday, April 28, 2010, at 3:00 pm (Calgary time) in the Strand/Tivoli Room of the Metropolitan Conference Centre, 333 – 4th Avenue S.W., Calgary, Alberta.

*Management's discussion and analysis ("MD&A") is a review of Zargon Energy Trust's 2009 financial results and should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2009 and 2008. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All amounts are in Canadian dollars unless otherwise noted. All references to "Zargon" or the "Trust" refer to Zargon Energy Trust and all references to the "Company" refer to Zargon Oil & Gas Ltd.*

*In the MD&A, reserves and production are commonly stated in barrels of oil equivalent ("boe") on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalent conversion method primarily applicable to the burner tip and does not represent a value equivalent at the wellhead.*

*The following are descriptions of non-GAAP measures used in this MD&A:*

- *The MD&A contains the term "funds flow from operating activities" ("funds flow"), which should not be considered an alternative to, or more meaningful than, "cash flows from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Trust's financial performance. This term does not have any standardized meaning as prescribed by GAAP and, therefore, the Trust's determination of funds flow from operating activities may not be comparable to that reported by other trusts. The reconciliation between cash flows from operating activities and funds flow from operating activities can be found in the table below and in the consolidated statements of cash flows in the consolidated financial statements. The Trust evaluates its performance based on net earnings and funds flow from operating activities. The Trust considers funds flow from operating activities to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt and to fund future capital investment. It is also used by research analysts to value and compare oil and gas trusts, and it is frequently included in published research when providing investment recommendations. Funds flow from operating activities per unit is calculated using the diluted weighted average number of units for the period.*

**Funds Flow from Operating Activities Reconciliation**

| ($ millions) | **2009** | 2008 | 2007 |
|---|---|---|---|
| Cash flows from operating activities | **88.83** | 110.12 | 76.30 |
| Changes in non-cash operating working capital | **(2.48)** | (3.21) | 3.54 |
| Funds flow from operating activities | **86.35** | 106.91 | 79.84 |

- *The Trust also uses the term "debt net of working capital" or "net debt". Debt net of working capital, as presented, does not have any standardized meaning prescribed by Canadian GAAP and may not be comparable with the calculation of similar measures for other entities. Debt net of working capital, as used by the Trust, is calculated as bank debt and any working capital deficit excluding unrealized risk management assets/liabilities and future income taxes.*

- *Operating netbacks per boe equal total petroleum and natural gas revenue per boe adjusted for realized risk management gains and/or losses per boe, royalties per boe and production costs per boe. Operating netbacks are a useful measure to compare the Trust's operations with those of its peers.*

- *Funds flow netbacks per boe are calculated as operating netbacks less general and administrative expenses per boe, interest and financing charges per boe, asset retirement expenditures per boe and current income taxes per boe. Funds flow netbacks are a useful measure to compare the Trust's operations with those of its peers.*

*References to "production volumes" or "production" in this document refer to sales volumes.*

*Forward-Looking Statements – This document offers our assessment of Zargon's future plans and operations as at March 9, 2010, and contains forward-looking statements including:*

- *our expectations for production costs referred to under the heading "Production Expenses";*
- *our expectations for taxes referred to under the headings "Current Income Taxes" and "Future Income Taxes";*
- *our expectations for key business parameters referred to under the heading "Funds Flow from Operating Activities";*
- *our expectations for interest expenses referred to under the heading "Bank Debt";*
- *our distribution policy referred to under the headings "2009 Highlights" and "Liquidity and Capital Resources";*
- *our expected sources of funds for distributions and capital expenditures referred to under the heading "Liquidity and Capital Resources";*
- *our expectations for the future impact of changes to environmental regulations referred to under the heading "Environmental Regulation and Risk";*
- *our expectations as to the impact of the recent global economic crisis to Zargon referred to under the heading "Business Risks";*
- *our expectations as to the impact of legislated modifications to Alberta Crown royalties referred to under the heading "Alberta Royalty and Tax Regime";*
- *our expectations for future commodity pricing and operating results referred to under the headings "Outlook"; and*
- *our expectations for designing and implementing International Financial Reporting Standards referred to under the heading "Recent and Future Canadian Accounting Pronouncements".*

*Such statements are generally identified by the use of words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "plan", "intend", "believe" and similar expressions (including the negatives thereof). By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including such as those relating to results of operations and financial condition, general economic conditions, industry conditions, changes in regulatory and taxation regimes, volatility of commodity prices, escalation of operating and capital costs, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel. Risks are described in more detail in our Annual Information Form, which is available on our website and at www.sedar.com. Forward-looking statements are provided to allow investors to have a greater understanding of our business.*

*You are cautioned that the assumptions, including among other things, future oil and natural gas prices; future capital expenditure levels; future production levels; future exchange rates; the cost of developing and expanding our assets; our ability to obtain equipment in a timely manner to carry out development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition, our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our development and acquisition activities used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. The forward-looking information contained in this document is expressly qualified by this cautionary statement. Our policy for updating forward-looking statements is that Zargon disclaims, except as required by law, any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.*

*This MD&A has been prepared as of March 9, 2010.*

## 2009 HIGHLIGHTS

Despite increased production volumes, significantly lower crude oil and natural gas prices resulted in Zargon achieving lower 2009 revenues and funds flow from operating activities when compared to 2008. During 2009, Zargon's revenue decreased by 32 percent to $155.99 million, which was primarily due to a 33 percent decrease in oil prices and a 47 percent decrease in natural gas prices that was slightly offset by a seven percent increase in production volumes. Zargon's 2009 funds flow from operating activities showed a 19 percent decrease to $86.35 million. Net earnings for the year were $2.72 million, a 96 percent decrease from 2008. The majority of the decrease in net earnings resulted from the above mentioned changes and from the large increase in non-cash unrealized risk management losses.

Net capital expenditures for 2009 totalled $104.59 million with $46.45 million from field-related activities, $1.04 million to net property acquisitions, $56.34 million to corporate acquisitions and $0.76 million to administrative assets. Compared to the prior year, the 2009 capital program showed a 13 percent decrease in overall net expenditures and a 13 percent decrease in field-related expenditures. For the year ended December 31, 2009, Zargon spent $5.60 million on undeveloped land; shot or acquired seismic at a cost of $3.71 million; drilled, equipped and tied-in wells for $37.14 million and concluded $57.38 million of corporate and net property acquisitions. Cash distributions to unitholders totalled $45.96 million during the 2009 year (2008 – $39.09 million). All of these activities were funded by the year's funds flow of $86.35 million plus the issuance of trust units valued at $65.14 million.

**Financial Highlights**

| ($ millions, except for per unit amounts) | **2009** | 2008 | 2007 |
|---|---|---|---|
| Petroleum and natural gas revenue | **155.99** | 229.49 | 155.51 |
| Funds flow from operating activities | **86.35** | 106.91 | 79.84 |
| Per unit – diluted | **3.64** | 5.18 | 4.08 |
| Cash flows from operating activities | **88.83** | 110.12 | 76.30 |
| Per unit – diluted | **3.74** | 5.34 | 3.90 |
| Net earnings | **2.72** | 68.29 | 24.55 |
| Per unit – diluted | **0.13** | 3.80 | 1.45 |
| Total assets | **464.38** | 447.60 | 343.11 |
| Net capital expenditures [1] | **104.59** | 119.73 | 66.67 |
| Bank debt | **76.58** | 77.58 | 56.87 |
| Cash distributions | **45.96** | 39.09 | 36.70 |

*(1) Amounts include capital expenditures for corporate and property acquisitions acquired for cash consideration, equity issuances, net debt assumed and are also inclusive of transaction costs.*

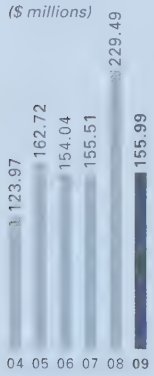
### Cash Distributions

Cash distributions to unitholders are at the discretion of the Board of Directors and can fluctuate depending on funds flow from operating activities. The Trust's capital program is financed from available funds flow, equity issuances and additional draw downs on the bank facilities, if required. The key drivers of Zargon's funds flow are commodity prices and production volumes. Since the Trust's production is relatively evenly weighted between oil and liquids (2009 – 51 percent) and natural gas (2009 – 49 percent), both commodity prices have a significant effect on its funds flow. In the event that oil and natural gas prices and/or production volumes are higher than anticipated and a cash surplus develops, the surplus may be used to increase distributions, reduce debt and/or increase the capital program. In the event that oil and natural gas prices and/or production volumes are lower than expected, the Trust may decrease distributions, increase debt and/or decrease the capital program. Zargon regularly reviews its monthly distribution policy in the context of the current commodity price environment, production levels and capital program requirements. Monthly distributions remained constant throughout 2009 at $0.18 per trust unit and have been maintained at this level since November 2005. In particular, realized price risk management gains of $27.69 million provided support in enabling Zargon to maintain distributions during the overall commodity price declines in 2009. Cash distributions to unitholders declared for 2009 totalled $45.96 million. For a further discussion, see the "Liquidity and Capital Resources" section of this report.

For Canadian income tax purposes, the 2009 cash distributions are 100 percent taxable income to unitholders.

## DETAILED FINANCIAL ANALYSIS

**Petroleum and Natural Gas Revenue**
*($ millions)*




### Petroleum and Natural Gas Revenue

Zargon derives its revenue from the production and sale of petroleum (oil and natural gas liquids) and natural gas. Petroleum and natural gas revenue, exclusive of the impact of financial risk management contracts, decreased 32 percent to $155.99 million in 2009 from $229.49 million in 2008 primarily due to decreased commodity prices throughout 2009 despite an increase in overall production. Compared to the prior year, the relative weighting of production revenue between petroleum and natural gas in 2009 was reallocated due to commodity pricing with 71 percent of the revenues coming from the sale of oil and liquids (62 percent in 2008) and 29 percent coming from the sale of natural gas (38 percent in 2008). Average production volumes on a barrel of oil equivalent basis in 2009 increased seven percent to 9,856 barrels of oil equivalent per day from the prior year amount of 9,252 barrels of oil equivalent per day. Specifically, in 2009, natural gas production decreased three percent and oil and liquids production increased 17 percent over 2008 levels. Production volume increases in oil and liquids resulted primarily from the 2009 second quarter corporate acquisition of Masters Energy Inc. ("Masters"), the third quarter corporate acquisition of Churchill Energy Inc. ("Churchill") and a successful Williston Basin oil exploitation program. Overall natural gas production decreases resulted from natural production declines that were not offset by drilling activity due to Zargon's relatively quiet natural gas field capital program, but were supported by additional natural gas volumes acquired in the Masters and Churchill corporate acquisitions. The average field price of oil and liquids received by Zargon decreased to $59.89 per barrel in 2009, down 33 percent from $89.65 per barrel in 2008. The average Zargon realized field price of natural gas was $4.32 per thousand cubic feet in 2009, a 47 percent decrease from $8.12 per thousand cubic feet in 2008.

**Pricing**

| Average for the year | **2009** | 2008 | 2007 |
|---|---|---|---|
| Natural Gas: | | | |
| NYMEX average daily spot price ($US/mmbtu) | **3.90** | 8.88 | 6.98 |
| AECO average daily spot price ($Cdn/mmbtu) | **3.96** | 8.16 | 6.45 |
| Zargon realized field price before the impact of financial risk management contracts ($Cdn/mcf) | **4.32** | 8.12 | 6.40 |
| Zargon realized field price before the impact of physical and financial risk management contracts ($Cdn/mcf) | **3.80** | 8.06 | 6.26 |
| Zargon realized field price after the impact of physical and financial risk management contracts ($Cdn/mcf) | **4.74** | 8.10 | 6.82 |
| Zargon realized natural gas field price differential/(premium) [1] | **(0.36)** | 0.04 | 0.05 |
| Zargon realized natural gas field price differential before the impact of physical and financial risk management contracts | **0.16** | 0.10 | 0.19 |
| Crude Oil: | | | |
| WTI ($US/bbl) | **61.80** | 99.65 | 72.31 |
| Edmonton par price ($Cdn/bbl) | **65.87** | 102.16 | 76.35 |
| Zargon realized field price before the impact of financial risk management contracts ($Cdn/bbl) | **59.89** | 89.65 | 64.71 |
| Zargon realized field price after the impact of financial risk management contracts ($Cdn/bbl) | **72.55** | 79.82 | 64.54 |
| Zargon realized oil field price differential [2] | **5.98** | 12.51 | 11.64 |

*(1) Calculated as Zargon's realized field price before the impact of financial risk management contracts ($Cdn/mcf) as compared to AECO average daily spot price ($Cdn/mmbtu). Note: premiums may occur as a result of the realization of fixed price physical contracts and the impact of Zargon receiving AECO monthly index pricing for a portion of its natural gas production.*

*(2) Calculated as Zargon's realized field price before the impact of financial risk management contracts ($Cdn/bbl) as compared to Edmonton par price ($Cdn/bbl).*

**Oil and Liquids Prices**
*($/bbl)*

## Petroleum (Oil and Natural Gas Liquids) Pricing

Zargon's field oil and natural gas liquids prices are adjusted at the point of sale for transportation charges and oil quality differentials from an Edmonton light sweet crude price that varies with world commodity prices. In 2009, Zargon's average oil and liquids field price, exclusive of the impact of financial risk management contracts, decreased 33 percent to $59.89 per barrel from $89.65 per barrel in 2008 and was seven percent lower than the $64.71 per barrel received in 2007. The field price differential for Zargon's average blended 30 degree API crude stream was $5.98 per barrel less than the 2009 Edmonton reference crude price, which compares to the 2008 differential of $12.51 per barrel and the 2007 differential of $11.64 per barrel. As the quality and weight of Zargon's crude stream has remained relatively consistent for several years, the movements in Zargon's price differential are derived from the North American refinery supply and demand factors for light and medium crudes. Oil and natural gas liquids transportation expenses are included in production expenses and are defined by the point of legal transfer of the product.

**Natural Gas Prices**
*($/mcf)*

## Natural Gas Pricing

The average field natural gas price, exclusive of the impact of financial risk management contracts, for 2009 decreased to $4.32 per thousand cubic feet, which is 47 percent lower than the 2008 average of

$8.12 per thousand cubic feet and 33 percent lower than the 2007 average of $6.40 per thousand cubic feet. Historically, Zargon's field prices have shown a small discount to the benchmark AECO average daily price due to the cost of the transmission of natural gas within Alberta. The 2009 field price differential for Zargon's natural gas before the impact of physical and financial risk management contracts was a discount of $0.16 per thousand cubic feet, compared to discounts of $0.10 and $0.19 per thousand cubic feet in 2008 and 2007, respectively. In 2009, the various fixed price physical contracts, which are treated as part of natural gas production revenue and natural gas pricing, created a gain of $5.03 million (2008 – $0.48 million), equivalent to an increase of $0.48 per thousand cubic feet (2008 – $0.04 per thousand cubic feet).

Approximately six percent of Zargon's 2009 natural gas production (2008 – 18 percent) was sold under aggregator contracts pursuant to long term contracts. The remainder of Zargon's natural gas production was sold by spot sale contracts and Alberta index prices were received.

### Risk Management Activities

Zargon's commodity price risk management policy, which is approved by the Board of Directors, allows the use of forward sales, costless collars and other instruments for up to a 24 month term and for up to 30 percent of the combined oil and natural gas working interest production volumes. Because our risk management strategy is protective in nature and is designed to guard the Trust against extreme effects on funds flow from sudden falls in prices and revenues, upward price spikes tend to produce overall losses.

For 2009, the total realized risk management gain was $27.69 million; compared to a loss of $15.72 million in 2008 and a gain of $4.26 million in 2007. Of the 2009 gain, $4.34 million (equivalent to an increase of $0.41 per thousand cubic feet) is related to a gain from natural gas financial risk management transactions, $23.36 million (equivalent to an increase of $12.66 per barrel) related to gains from oil financial risk management transactions (foreign exchange contracts are considered in conjunction with the oil contracts) and $0.01 million is related to a loss from electricity risk management transactions. Oil swaps and collars are settled against the NYMEX WTI pricing index, whereas natural gas swaps, collars and puts are settled against the AECO monthly pricing index. Electricity swaps are settled against the AESO pricing index. In 2009, NYMEX WTI crude oil prices rose throughout the first half of the year before holding relatively steady for the remainder of the year. AECO natural gas prices continued to trend lower throughout the first eight months, finding its low for the August month before beginning to trend upwards. These lower prices, relative to the respective risk management contracts, resulted in overall year-to-date realized risk management gains for 2009.

Zargon's management considers financial risk management contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes, and, accordingly, for these contracts, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at year end. The 2009 net unrealized risk management loss totalled $36.39 million, which compares to a $44.38 million net unrealized risk management gain in 2008 (2007 – $16.80 million loss). Specifically, the 2009 net unrealized risk management losses resulted from financial oil contract losses ($34.70 million), financial natural gas contract losses ($2.87 million) and financial electricity contract losses ($0.13 million) and were offset by financial foreign exchange contract gains ($1.31 million). These unrealized risk management gains or losses are generated by the change over the reporting period in the mark-to-market valuation of Zargon's future financial contracts. Gains or losses on fixed price physical contracts are included in petroleum and natural gas revenue when settled in the statements of earnings and comprehensive income and accumulated earnings and no mark-to-market valuation is recorded on these contracts.

As at December 31, 2009, the Trust had the following outstanding commodity, electricity and foreign exchange risk management contracts:

**Commodity Financial Risk Management Contracts:**

| | Rate | Weighted Average Price | Range of Terms |
|---|---|---|---|
| Oil swaps | 300 bbl/d | $132.98 US/bbl | Jan. 1/10 – Jun. 30/10 |
| | 1,400 bbl/d | $73.11 US/bbl | Jan. 1/10 – Dec. 31/10 |
| | 400 bbl/d | $77.40 US/bbl | Jan. 1/10 – Jun. 30/11 |
| | 300 bbl/d | $83.30 US/bbl | Jul. 1/10 – Dec. 31/10 |
| | 300 bbl/d | $77.25 US/bbl | Jan. 1/11 – Sep. 30/11 |

**Foreign Exchange Financial Risk Management Contracts:**

| | Average Monthly US Dollar Volume ($ thousands) | Foreign Exchange Rate ($Cdn/$US) | Range of Terms |
|---|---|---|---|
| Foreign exchange forwards | 1,203 | 1.1715 | Jan. 1/10 – Jun. 30/10 |

**Electricity Financial Risk Management Contracts:**

| | Rate | Weighted Average Price | Range of Terms |
|---|---|---|---|
| Electricity forwards | 6 MWs/d | $80.42/MWh | Jan. 1/10 – Dec. 31/10 |
| | 6 MWs/d | $79.33/MWh | Jan. 1/11 – Dec. 31/11 |

**Physical Risk Management Contracts:**

| | Rate | Weighted Average Price | Range of Terms |
|---|---|---|---|
| Electricity forwards | 32 MWs/d | $55.50/MWh | Jan. 1/10 – Mar. 31/11 |

## Royalties

Royalties include payments made to the Crown, freehold owners and third parties. Reported royalties also include the cost of the Saskatchewan Resource Surcharge ("SRC") and the cost of North Dakota state taxes. During 2009, total royalties were $27.42 million, a decrease of 41 percent from $46.64 million in 2008. The variations in royalty rates generally track changes in production volumes and prices. Commencing in 2009, the oil and natural gas royalty structure changed for Alberta production volumes. Further discussion regarding this issue is provided later in this report under the heading "Capital Expenditures". Reflecting the relatively lower commodity prices and modified royalty structure, on a consolidated basis, royalties, as a percentage of gross revenue, were 17.6 percent in 2009 (18.2 percent excluding revenue that does not attract royalty expenses) compared to 20.3 percent in 2008 and 21.1 percent in 2007. On a commodity basis, natural gas royalties averaged 10.4 percent in 2009, a decrease from the previous year's average of 19.7 percent, resulting primarily from lower royalties associated with lower natural gas pricing under the modified Alberta royalty structure. Oil royalties averaged 20.5 percent, down slightly from the prior year rate of 20.7 percent. The decrease in oil royalties is primarily related to initial low royalty rate incentives on certain new oil production wells in Saskatchewan and Alberta.

During 2009, 49 percent (2008 – 58 percent) of the total royalties were paid to provincial and state governments, with the remainder paid to freehold owners and other third parties. The SRC charges were $1.08 million in 2009, down from $1.63 million in the prior year and from $1.10 million in 2007, reflecting the trend in Saskatchewan oil revenues. North Dakota state taxes decreased to $0.97 million in 2009 from $2.47 million in the prior year primarily due to decreased sales revenue (lower oil prices received) and decreased oil production and sales for the US operations.

### Production Expenses

Zargon's production expenses increased 19 percent to $47.56 million in 2009 from $39.91 million in 2008, reflecting, in part, the addition of higher cost properties acquired in recent corporate acquisitions. On a per unit of production basis, production expenses increased 12 percent to $13.22 per barrel of oil equivalent from $11.79 in 2008 ($10.44 in 2007).

Natural gas production expenses in 2009 rose 38 percent to $2.14 per thousand cubic feet from $1.55 per thousand cubic feet in 2008. The primary reasons for the increase are decreased natural gas production volumes, increased third party natural gas gathering and processing fees and increased water disposal and water hauling costs. These increased costs reflect the impact of additional natural gas volumes being processed through non-operated third party natural gas gathering and processing facilities.

Oil production expenses decreased in 2009 to $13.56 per barrel, a decrease of seven percent from $14.63 per barrel in 2008. The primary reason for the decrease is due to increased production volumes, which more than offset charges due to increased workovers and increased repairs and annual maintenance programs.

In 2009, 2008 and 2007, Zargon's costs increased substantially due, in general, to the effect of industry-wide production cost inflation pressures, which may now be somewhat abating due to lower industry activity levels in response to recent oil and natural gas price declines. In particular, operating costs averaged $13.09 per barrel of oil equivalent in the fourth quarter of 2009 down from $13.18 per barrel of oil equivalent in the 2009 third quarter. For 2010, Zargon anticipates a continued moderation in upward cost pressures and anticipates maintaining operating costs in the $13.00 to $14.00 per barrel of oil equivalent range.

### Operating Netbacks

The average oil and liquids price received, after realized risk management gains/losses, in 2009 of $72.55 per barrel was nine percent lower than the $79.82 per barrel received in 2008. The average natural gas price received, after realized risk management gains/losses, in 2009 of $4.74 per thousand cubic feet was 41 percent below the $8.10 per thousand cubic feet received in 2008. Operating netbacks decreased commensurately. Supported by realized risk management gains, oil and liquids netbacks were relatively even at $46.72 per barrel up slightly from $46.60 per barrel in 2008. Natural gas netbacks decreased 57 percent to $2.15 per thousand cubic feet from $4.95 per thousand cubic feet in 2008. On a barrel of oil equivalent basis, 2009 operating netbacks decreased 20 percent to $30.22 from $37.56 in 2008.

**Operating Netbacks**

| | 2009 | | 2008 | |
|---|---|---|---|---|
| | **Oil and Liquids ($/bbl)** | **Natural Gas ($/mcf)** | Oil and Liquids ($/bbl) | Natural Gas ($/mcf) |
| Production revenue | **59.89** | **4.32** | 89.65 | 8.12 |
| Realized risk management gain/(loss) | **12.66** | **0.42** | (9.83) | (0.02) |
| Royalties | **(12.27)** | **(0.45)** | (18.59) | (1.60) |
| Production costs | **(13.56)** | **(2.14)** | (14.63) | (1.55) |
| Operating netbacks | **46.72** | **2.15** | 46.60 | 4.95 |

## General and Administrative Expenses

Gross general and administrative costs increased 26 percent in 2009 to $17.38 million from $13.80 million in 2008. On a per unit of production basis, net general and administrative costs increased 24 percent to $3.83 per barrel of oil equivalent compared to $3.08 per barrel of oil equivalent in 2008 and $2.63 in 2007. Trending upwards from 2007 and 2008, the 2009 increased general and administrative costs on a per unit of production basis is primarily due to additional office lease costs associated with corporate acquisitions, amounts recorded for year end performance-based compensation and costs related to the expansion of Zargon's technical staff and consultants as Zargon repositions itself for its expanded exploitation and acquisition initiatives. The 2009 expenses included approximately $0.19 per barrel of equivalent of one-time employment related charges.

**General and Administrative Expenses**

| ($ millions, except as noted) | **2009** | 2008 | 2007 |
|---|---|---|---|
| Gross general and administrative expenses | **17.38** | 13.80 | 11.69 |
| Overhead recoveries | **(3.61)** | (3.35) | (3.48) |
| Net general and administrative expenses | **13.77** | 10.45 | 8.21 |
| Net expense after recoveries ($/boe) | **3.83** | 3.08 | 2.63 |
| Number of office employees at year end | **57** | 53 | 45 |

## Interest and Financing Charges

Zargon's borrowings are through its syndicated bank credit facilities. Interest and financing charges were $3.02 million compared to $4.91 million in 2008 and $3.07 million in 2007. A decrease in the average debt level and lower borrowing costs for the first half of 2009 (prior to renewal of Zargon's credit facilities) are the primary reasons for the decrease in interest and financing charges. In particular, bank debt levels were decreased in June 2009, when the Trust closed an offering of 2.365 million trust units on a bought deal basis at $15.00 per unit for total gross proceeds of $35.48 million ($33.44 million net of equity issuance expenses). Zargon's effective interest and financing charge rate was 3.5 percent on an average outstanding bank debt of $85.38 million in 2009, compared to 5.2 percent on an average bank debt of $95.07 million in 2008 and 6.2 percent on an average bank debt of $49.86 million in 2007. At year end 2009, Zargon's bank debt, net of working capital (excluding unrealized risk management assets/liabilities and future income taxes), totalled $88.01 million, up slightly from $87.71 million at December 31, 2008. This increase reflected the net debt acquired and cash consideration paid in the corporate acquisitions of Masters Energy Inc. and Churchill Energy Inc., which was mostly offset by the application of proceeds from the trust unit offering. For more information on Zargon's credit facilities, see the "Bank Debt" section of this report.

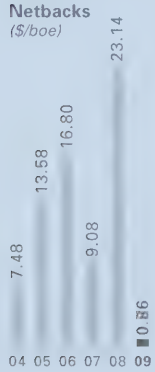
## Current Income Taxes

Current income taxes for 2009 were $2.49 million compared to $4.05 million in 2008. Of the total, $2.21 million is due to current taxes incurred in the United States compared to $3.08 million in 2008. On a year-over-year comparison, current income taxes have decreased due to a reduction in 2009 taxable income in the United States related to lower revenue attributed to relatively lower oil prices in 2009. The remaining current tax amounts relate to withholding taxes on US dividends declared from Zargon's US subsidiary to its parent corporation and Canadian provincial capital taxes, which, in aggregate, totalled $0.28 million in 2009 compared to $0.97 million in 2008.

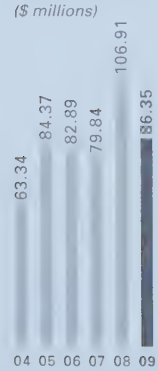
Tax pools as at December 31, 2009 were approximately $293 million, which represents an increase from the comparable $188 million of tax pools available to Zargon at the end of 2008, primarily due to the tax pools acquired in the Masters and Churchill acquisitions. The Trust is a taxable entity under the Income Tax Act (Canada) and is currently only taxable (until 2011) on the income that is not distributed or declared distributable to unitholders. For a further discussion on the Trust's conversion plans, see the "Future Income Taxes" section later in this report.

**Funds Flow Netbacks**
*($/boe)*

**Earnings Before Non-Controlling Interest Netbacks**
*($/boe)*




**Funds Flow from Operating Activities**
*($ millions)*




For Canadian income tax purposes, 2009 cash distributions are 100 percent taxable income to unitholders.

### Trust Netbacks

Lower oil and natural gas prices in 2009 were supported by realized risk management gains resulting in relatively strong revenue netbacks and operating netbacks. On a barrel of oil equivalent basis, revenue of $43.36 in 2009 was 36 percent lower than the prior year and operating netbacks, as well as funds flow netbacks, decreased 20 percent and 24 percent, respectively, from the prior year to $30.22 and $24.01 per barrel of oil equivalent, respectively.

**Trust Netbacks**

| ($/boe) | **2009** | 2008 | 2007 |
|---|---|---|---|
| Petroleum and natural gas revenue | **43.36** | 67.77 | 49.77 |
| Realized risk management gain/(loss) | **7.70** | (4.65) | 1.36 |
| Royalties | **(7.62)** | (13.77) | (10.48) |
| Production costs | **(13.22)** | (11.79) | (10.44) |
| Operating netbacks | **30.22** | 37.56 | 30.21 |
| General and administrative | **(3.83)** | (3.08) | (2.63) |
| Interest and financing charges | **(0.84)** | (1.45) | (0.98) |
| Asset retirement expenditures | **(0.85)** | (0.26) | (0.36) |
| Current income taxes | **(0.69)** | (1.20) | (0.69) |
| Funds flow netbacks | **24.01** | 31.57 | 25.55 |

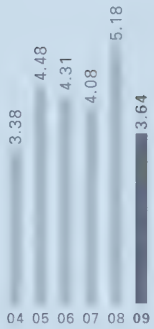
### Funds Flow from Operating Activities (see note at the beginning of the MD&A)

In 2009, production volume increases of seven percent on a barrel of oil equivalent basis were more than offset by decreased revenue of 36 percent per barrel of oil equivalent and the increase in cash operating costs during the year to produce a 19 percent decrease in funds flow from operating activities to $86.35 million, compared to $106.91 million in 2008 and $79.84 million in 2007. The corresponding funds flow per diluted unit was $3.64 in 2009, a 30 percent decrease from $5.18 in 2008 and an 11 percent decrease from $4.08 in 2007. The diluted per unit statistics reflect a 15 percent increase in the weighted average outstanding units to 23.75 million in 2009 from 20.63 million in 2008. The 2008 weighted average outstanding units were also six percent higher than the 2007 amount of 19.55 million.

The following table summarizes the variances in funds flow from operating activities between 2008 and 2009. It demonstrates that the variance (decrease in funds flow from operating activities) is caused primarily by a decrease in realized commodity prices and increased operating expenses despite increased production volumes, increased realized risk management gains and decreased royalties.

| | $ Million | $ Per Diluted Trust Unit | Per Unit Percent Variance |
|---|---|---|---|
| **Funds flow from operating activities – 2008** | **106.91** | **5.18** | **–** |
| Price variance | (83.08) | (3.50) | (68) |
| Volume variance | 9.56 | 0.40 | 8 |
| Realized risk management gains | 43.41 | 1.83 | 35 |
| Royalties | 19.22 | 0.81 | 16 |
| Expenses: | | | |
| Production | (7.65) | (0.32) | (6) |
| General and administrative | (3.32) | (0.14) | (3) |
| Interest and financing charges | 1.90 | 0.08 | 2 |
| Asset retirement expenditures | (2.16) | (0.09) | (2) |
| Current taxes | 1.56 | 0.07 | 1 |
| Weighted average trust units – diluted | – | (0.68) | (13) |
| **Funds flow from operating activities – 2009** | **86.35** | **3.64** | **(30)** |

**Funds Flow Per Unit**
*($/unit – diluted)*




### Depletion and Depreciation

In 2009, Zargon's depletion and depreciation provision increased nine percent to $64.72 million, compared to $59.64 million in 2008 and $48.41 million in 2007. The higher charges reflect an increase of seven percent in production volumes and a two percent increase in the charge on a per barrel of oil equivalent basis. Depletion and depreciation charges calculated on a unit of production method are based on total proved reserves with a conversion of six thousand cubic feet of natural gas being equivalent to one barrel of oil. The 2009 depletion calculation includes $7.80 million of future capital expenditures to develop the Trust's reserves, but excludes $24.37 million of unproven properties relating to undeveloped land.

Zargon's depletion and depreciation, on a barrel of oil equivalent basis, increased two percent in 2009 to $17.99 from $17.61 in 2008 and also increased 16 percent from the 2007 rate of $15.49.

**Cash Flows from Operating Activities**
*($ millions)*

### Accretion of Asset Retirement Obligations

For the year ended December 31, 2009, the non-cash accretion expense for asset retirement obligations was $2.74 million compared to $2.18 million in 2008 and $1.41 million in 2007. The year-over-year increases are due to changes in the estimated future liability for asset retirement obligations as a result of wells added through Zargon's drilling program inclusive of wells acquired/disposed of in the year and wells acquired with the recent Masters and Churchill corporate acquisitions. The significant assumptions used in this calculation are a credit adjusted risk-free rate of 7.5 percent, an inflation rate of two percent and the payments to settle the retirement obligations occurring over the next 40 years, with the majority of the costs being incurred after 2019. The estimated net present value of the total asset retirement obligation is $35.47 million as at December 31, 2009, based on a total future liability of $164.58 million.

**Cash Flows Per Unit**
*($/unit – diluted)*

### Unit-Based Compensation

Unit-based compensation was $1.26 million in 2009, $0.07 million higher than the $1.19 million expense in 2008. The increase in the current year expense is a result of the timing of 2009 grants and a general increase in the valuation of these new grants. Zargon will continue to use fair value methodologies for future unit rights grants. These non-cash expenses will be recurring charges in future years if Zargon continues to grant employees and directors trust unit rights.

The Trust has a unit rights incentive plan (the "Old Plan") that allows the Trust to issue rights to acquire trust units to directors, officers, employees and other service providers. On April 22, 2009, a new unit rights incentive plan (the "New Plan") was approved. The Trust is authorized to issue up to an aggregate

of 2.13 million unit rights; however, the number of trust units reserved for issuance upon exercise of the rights shall not at any time exceed 10 percent of the aggregate number of the total outstanding units, including units issuable upon exchange of exchangeable shares of Zargon and other fully paid securities of Zargon entities exchangeable into units, which are the economic equivalent of units including full voting rights. At the time of grant, unit right exercise prices approximate the market price for the trust units. At the time of exercise, the rights holder has the option of exercising at the original grant price or the exercise price as calculated under the Old Plan or the New Plan (the "modified price"). Under the Old Plan, the modified price was based on the increment of the amount the monthly distribution exceeded a monthly return of 0.833 percent of the Trust's recorded net book value of oil and natural gas properties (as defined in the Old Plan). Under the New Plan, if the monthly distribution exceeds the monthly return of 0.833 percent of the Trust's recorded net book value of oil and natural gas properties (as defined in the New Plan), the entire amount (not the increment) of the distribution is deducted from the original grant price. Rights granted under either Plan generally vest over a three-year period and expire approximately five years from the grant date. Zargon uses a fair value methodology to value the unit rights grants.

### Unrealized Foreign Exchange

Unrealized foreign exchange losses of $0.18 million in 2009 compare to gains of $1.96 million for 2008. Gains and losses result from translations of Zargon's US subsidiaries into Canadian dollars at rates as determined under the temporal method of converting foreign subsidiaries as required by Canadian GAAP. The volatility in the US/Cdn dollar has created non-cash translation gains/losses as recorded in Zargon's income statement.

### Future Income Taxes

The provision for the future tax recovery for 2009 was $18.95 million when compared to a future tax expense of $12.75 million in 2008 and a recovery of $15.47 million in 2007. Effectively, Zargon's future tax obligations are reduced as distributions are made from the Trust and, consequently, it is anticipated that Zargon's effective tax rate will continue to be low through to 2011. The 2009 future tax recovery, when compared to the 2008 prior year expense, is significantly impacted by the decrease in earnings before income taxes for the period as a result of previously mentioned items such as decreased commodity prices and increased unrealized risk management losses.

On October 31, 2006, the Federal Government announced tax proposals pertaining to taxation of distributions paid by trusts and the personal tax treatment of trust distributions. Currently, the Trust does not pay tax on distributions as tax is paid by the unitholders. On June 12, 2007, the Federal Government enacted these tax proposals, which would have resulted in taxation of distributions at the Trust level at a rate of 31.5 percent effective January 1, 2011. Subsequent 2007 fourth quarter legislation lowered this tax rate to 29.5 percent in 2011 and 28.0 percent beyond 2011. Prior to June 2007, the Trust estimated the future income tax on certain temporary differences between amounts recorded on its balance sheet for book and tax purposes to have a nil effective tax rate. On February 26, 2008, the Federal Government, in its Federal Budget, announced further changes to the specified investment flow through ("SIFT") tax rules. The provincial component of the SIFT tax will be based on the provincial rates where the SIFT has a permanent establishment rather than using a 13.0 percent flat provincial rate. During the 2009 first quarter this tax rate change had been substantively enacted, and the future income tax impact has been recorded in the financial statements. Under the legislation, the Trust now estimates the effective tax rate on the post 2010 reversal of these temporary differences to be approximately 26.5 percent for 2011 and 25.0 percent thereafter. Until 2011, Zargon's future tax obligations are reduced as distributions are made from the Trust and, consequently, it is anticipated that Zargon's effective tax rate will continue to be low until that time.

On December 15, 2006, the Canadian Federal Department of Finance stated its intention to allow conversions of SIFT income trusts to a corporation without any adverse tax consequences to investors. On July 14, 2008, the Department of Finance released the draft legislative proposals to allow the conversion of these SIFT trusts into corporations. Zargon is currently reviewing and assessing this recent legislation and is considering its potential impact on the organization while Zargon's management

develops its strategic plan beyond December 2010, which is the effective date of the new SIFT tax rules. Zargon's current plans are to convert from its trust structure to a corporation at the end of 2010 or early in 2011. Zargon's management continues to believe that a partial cash flow distributing model is an effective model to produce conventional oil and gas assets in our relatively mature sedimentary basins, and as such plans to distribute regular dividends under the corporate structure.

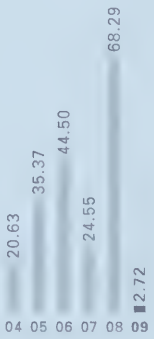
### Non-Controlling Interest – Exchangeable Shares

According to the January 19, 2005 CICA pronouncement, EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts", Zargon Energy Trust must reflect the exchangeable securities issued by its subsidiary, Zargon Oil & Gas Ltd. as either a non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by Zargon Oil & Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as a non-controlling interest. Prior to 2005, these exchangeable shares were reflected as a component of unitholders' equity.

Accordingly, the Trust has increased its unitholders' equity and non-controlling interest for 2009 by $1.04 million (2008 – $12.52 million) on the Trust's consolidated balance sheets. Consolidated net earnings for 2009 have been reduced for net earnings attributable to the non-controlling interest by $0.34 million (2008 – $10.10 million). In accordance with EIC-151, and given the circumstances in Zargon's case, each redemption is accounted for as a step-purchase, which, for 2009, resulted in an additional increase in property and equipment of $0.97 million (2008 – $3.39 million) and an increase in the future income tax liability of $0.27 million (2008 – $0.97 million). Funds flow from operating activities were not impacted by this change.

The cumulative impact to date of the application of EIC-151 has been to increase gross property and equipment by $56.13 million (for depletion impact see note 5 in the audited consolidated financial statements), unitholders' equity and non-controlling interest by $66.91 million, future income tax liability by $18.46 million and an allocation of net earnings to exchangeable shareholders of $29.24 million.

**Net Earnings**
*($ millions)*

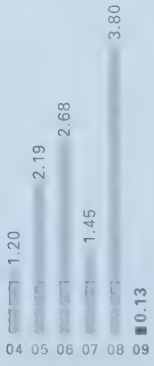



### Net Earnings

Zargon's 2009 net earnings were $2.72 million, a 96 percent decrease from $68.29 million in 2008. The 2007 net earnings were $24.55 million. The net earnings track the funds flow from operating activities for the respective periods modified by asset retirement expenditures and non-cash charges, which, in 2009; includes depletion and depreciation, unrealized risk management gains/losses, future income tax expenses/recoveries, unit-based compensation and non-controlling interest. On a per diluted unit basis, 2009 net earnings were $0.13 compared to net earnings of $3.80 in 2008 and $1.45 in 2007.

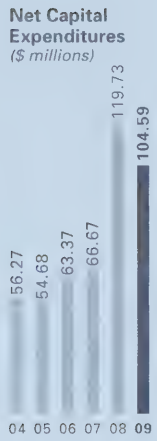
The 2009 net earnings were three percent of funds flow from operating activities, primarily reflecting the increase in non-cash charges (net of tax) such as unrealized risk management losses and depletion. The 2008 net earnings represented 64 percent of funds flow from operating activities compared to 31 percent of funds flow from operating activities in 2007.

**Net Earnings Per Unit**
*($/unit – diluted)*




### Capital Expenditures

Total net capital expenditures (including net property acquisitions, cash and equity consideration and net debt assumed for corporate acquisitions) in 2009 of $104.59 million decreased 13 percent from $119.73 million in 2008, and was highlighted by $56.34 million attributed to the corporate acquisitions of Masters and Churchill. Zargon's field capital expenditure program also declined 13 percent in 2009 to $46.45 million from the $53.35 million 2008 field capital expenditure program. In 2009, Zargon drilled 29 gross (25.7 net) wells compared to 39 gross (35.9 net) wells in 2008 and, as a result, drilling and completion expenditures decreased commensurately by 21 percent to $21.94 million. Of the total 2009 field capital expenditures (excluding corporate and net property acquisitions), $8.67 million were expended on West Central Alberta, $18.29 million on Alberta Plains and $19.49 million on Williston Basin properties. Additionally, $0.76 million was incurred corporately on leasehold improvements and




administrative assets and $57.38 million was attributed to the corporate and net property acquisitions. Field capital expenditures for the 2009 year are net of $2.40 million and $0.40 million in Alberta drilling credits in the respective Alberta Plains and West Central Alberta core areas. Alberta drilling credits are designed to encourage the execution of new drilling projects in Alberta and were announced in response to the slow-down in drilling throughout the province. The drilling credit is based on a $200 per metre credit on total metres drilled with a cap based on production levels and Alberta Crown royalties paid.

**Capital Expenditures**

| ($ millions) | **2009** | 2008 | 2007 |
|---|---|---|---|
| Undeveloped land | **5.60** | 8.14 | 7.49 |
| Geological and geophysical (seismic) | **3.71** | 4.44 | 4.41 |
| Drilling and completion of wells | **21.94** | 27.66 | 33.15 |
| Well equipment and facilities | **15.20** | 13.11 | 18.49 |
| Exploration and development | **46.45** | 53.35 | 63.54 |
| Property acquisitions [1] | **1.17** | 6.41 | 3.04 |
| Property dispositions | **(0.13)** | (0.22) | (1.18) |
| Net property acquisitions/(dispositions) [1] | **1.04** | 6.19 | 1.86 |
| Corporate acquisitions assigned to property and equipment [2] | **56.34** | 59.85 | – |
| Total net capital expenditures excluding administrative assets [1] [2] | **103.83** | 119.39 | 65.40 |
| Administrative assets | **0.76** | 0.34 | 1.27 |
| Total net capital expenditures [1] [2] | **104.59** | 119.73 | 66.67 |

*(1) Amounts include capital expenditures acquired for cash and equity issuances.*

*(2) Amounts include capital expenditures acquired for cash, equity issuances, acquisition costs and net debt assumed on corporate acquisitions.*

## CORPORATE ACQUISITIONS

On April 29, 2009, a subsidiary of the Trust acquired all of the issued and outstanding common shares of Masters Energy Inc. ("Masters"), a public oil and gas company, for a total consideration of 1,475,468 Zargon trust units, $5.70 million in cash and the assumption of approximately $13.29 million of net debt (including adjustments and transaction costs) for a total transaction value of $40.03 million.

The results of operations for Masters have been included in the consolidated financial statements since April 29, 2009. In relation to the 2009 year, the Masters acquisition has contributed approximately 697 barrels of oil equivalent per day of production volumes to Zargon's total average production volumes of 9,856 barrels of oil equivalent per day and has provided a significant Alkaline Surfactant Polymer (ASP) tertiary oil recovery opportunity at the Little Bow oil property in Southern Alberta.

On September 23, 2009, a subsidiary of the Trust acquired all of the issued and outstanding shares of Churchill Energy Inc. ("Churchill"), a public oil and gas company, for a total consideration of 554,669 Zargon trust units, $0.11 million in cash and the assumption of approximately $6.85 million of net debt (including adjustments and transaction costs) for a total transaction value of approximately $16.31 million. This acquisition brought oil exploitation opportunities at Grand Forks and Brazeau, Alberta along with significant tax pools.

The results of operations for Churchill have been included in the consolidated financial statements since September 23, 2009. In relation to the 2009 year, the Churchill acquisition has contributed approximately 87 barrels of oil equivalent per day of production volumes to Zargon's total average production volumes of 9,856 barrels of oil equivalent per day.

## LIQUIDITY AND CAPITAL RESOURCES

In 2009, the summation of the funds inflows coming from the funds flow from operating activities ($86.35 million) plus the issuance of trust units ($65.14 million - arising from the acquisitions of Masters and Churchill, the equity issuance and unit right exercises) exceeded the summation of the funds outflows pertaining to the net capital expenditure program ($104.59 million) and the cash distributions to unitholders ($45.96 million) by $0.94 million.

Zargon's financing philosophy and the three sources of funding are as follows:

- Internally generated funds flow from operating activities provides the basic level of funding for the Trust's annual capital expenditures program and for distributions to unitholders.
- Debt may be utilized for acquisitions or to expand capital programs when it is deemed appropriate. As at December 31, 2009, the Trust had $180 million in syndicated committed credit facilities of which $102.81 million or 57 percent of these facilities were unutilized.
- New equity, if available and if on favourable terms, can be utilized for acquisitions or to expand capital programs.

The volatility of oil and natural gas prices, the changes relating to Alberta royalties and Canadian income trust tax rules and global economic concerns have partially restricted the oil and natural gas industry's ability to attract new capital from debt and equity markets. Zargon's historically conservative strategy of maintaining a relatively low cash distribution to funds flow ratio and conservative debt levels enabled Zargon to fund its capital and distribution programs during 2009.

On June 5, 2009, the Trust closed an offering of 2.365 million trust units on a bought deal basis at $15.00 per unit for total gross proceeds of $35.48 million ($33.44 million net of equity issuance costs). The net proceeds of the offering were used to reduce outstanding borrowings under existing credit facilities, and, in turn, were also used to partially fund the 2009 capital expenditure program and for general corporate purposes.

**Cash Distributions Analysis**

| ($ millions) | **2009** | 2008 | 2007 |
|---|---|---|---|
| Cash flows from operating activities | **88.83** | 110.12 | 76.30 |
| Net earnings | **2.72** | 68.29 | 24.55 |
| Actual cash distributions paid or payable relating to the period | **(45.96)** | (39.09) | (36.70) |
| Excess of cash flows from operating activities over cash distributions paid | **42.87** | 71.03 | 39.60 |
| Excess (shortfall) of net earnings over cash distributions paid | **(43.24)** | 29.20 | (12.15) |

During the twelve months of 2009, Zargon has maintained a base monthly distribution of $0.18 per trust unit. Management monitors the Trust's distribution policy with respect to forecasted net cash flows, debt levels and capital expenditures. Zargon's cash distributions are discretionary to the extent that these distributions do not cause a breach of the financial covenants under Zargon's credit facilities and to the extent the Trust (non-consolidated) is not taxable. As a crude oil and natural gas Trust, Zargon's reserve base is depleted with production and Zargon, therefore, relies on ongoing exploration, development and acquisition activities to replace reserves and to offset production declines. The success of these exploration, development and acquisition capital programs, along with commodity price fluctuations and the Trust's ability to manage costs, are the main factors influencing the sustainability of the Trust's distributions.

For the year ended December 31, 2009, cash flows from operating activities (after changes in non-cash working capital) of $88.83 million exceeded cash distributions of $45.96 million. This was consistent with

the year ended December 31, 2008, in which cash flows from operating activities (after changes in non-cash working capital) of $110.12 million exceeded cash distributions of $39.09 million.

For the year ended December 31, 2009, cash distributions of $45.96 million exceeded net earnings of $2.72 million. Net earnings include significant non-cash charges ($86.69 million in 2009), particularly unrealized risk management losses and depletion and depreciation that do not impact cash flows. For the year ended December 31, 2008, cash distributions of $39.09 million were exceeded by net earnings of $68.29 million. Net earnings also include fluctuations in future income taxes due to changes in tax rates and tax rules. In addition, other non-cash charges such as depletion and depreciation are not a good proxy for the cost of maintaining Zargon's productive capacity given the natural declines associated with crude oil and natural gas assets. In the instances where distributions exceed net earnings, a portion of the cash distribution paid to unitholders may represent an economic return of the unitholders' capital.

For the year ended December 31, 2009, cash distributions and net capital expenditures totalled $150.55 million ($120.15 million excluding the $30.40 million of equity issuances attributed to corporate acquisitions), which was $61.72 million higher than cash flows from operating activities (after changes in non-cash working capital) of $88.83 million. For the year ended December 31, 2008, cash distributions and net capital expenditures totalled $158.82 million, which was $48.70 million higher than cash flows from operating activities (after changes in non-cash working capital) of $110.12 million. Zargon relies on access to debt and capital markets to the extent cash distributions and net capital expenditures exceed cash flows from operating activities (after changes in non-cash working capital). Over the long term, Zargon expects to fund cash distributions or dividends and capital expenditures with its cash flows from operating activities; however, it will continue to fund acquisitions and growth through additional debt and equity issuances. In the crude oil and natural gas industry, because of the nature of reserve reporting, the natural reservoir declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities, therefore, maintenance capital is not disclosed separately from development capital spending.

**Capital Sources and Uses**

| ($ millions) | **2009** | 2008 | 2007 |
|---|---|---|---|
| Funds flow from operating activities | **86.35** | 106.91 | 79.84 |
| Change in bank debt | **(1.00)** | 20.71 | 26.83 |
| Issuance of trust units | **65.14** | 25.08 | 2.13 |
| Cash distributions to unitholders | **(45.96)** | (39.09) | (36.70) |
| Changes in working capital and other | **0.06** | 6.12 | (5.43) |
| Total capital sources | **104.59** | 119.73 | 66.67 |

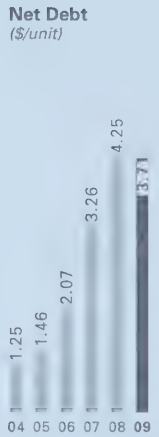
## Funds Flow from Operating Activities

It is anticipated that Zargon's 2010 exploration and development capital budget and cash distributions to unitholders will be financed through the Trust's funds flow from operating activities and its credit facilities. Funds flow is partially influenced by factors that the Trust cannot control, such as commodity prices, the US/Canadian dollar exchange rates and interest rates. Zargon's 2010 estimated sensitivity to moderate fluctuations in these key business parameters is shown in the accompanying table.

**Funds Flow Sensitivity Summary**

| | Change in 2010 Funds Flow | |
|---|---|---|
| | ($ millions) | ($/unit) |
| Change of $1.00 US/bbl in the price of WTI oil | 1.75 | 0.07 |
| Change in oil production of 100 bbl/d | 2.07 | 0.08 |
| Change of $0.10 US/mcf in the price of NYMEX natural gas | 0.71 | 0.03 |
| Change in natural gas production of one mmcf/d | 1.56 | 0.06 |
| Change of $0.01 in the $US/$Cdn exchange rate | 1.81 | 0.07 |

## Bank Debt




On July 27, 2009, Zargon amended and renewed its syndicated committed credit facilities, the result of which was the maintaining of the available facilities and borrowing base of $180 million. These facilities consist of a $170 million tranche available to the Canadian borrower and a US $8 million tranche available to the US borrower. A $300 million demand debenture on the assets of the subsidiaries of the Trust has been provided as security for these facilities. The facilities are fully revolving for a 336 day period with the provision for an annual extension at the option of the lenders and upon notice from Zargon's management. The next renewal date is June 29, 2010. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 336 day period. Repayment would not be required until the end of the non-revolving term, and, as such, these facilities have been classified as long term debt. These facilities continue to be available for general corporate purposes and the potential acquisition of additional oil and natural gas properties such as those most recently acquired through the corporate acquisitions of Masters Energy Inc. and Churchill Energy Inc. which were funded by bank debt and equity issuances. Zargon reviews its compliance with its bank debt covenants on a quarterly basis and has no violations as at December 31, 2009. Zargon's management is planning to convert to a corporation from its current trust structure towards the end of 2010. In order for this conversion to occur, Zargon would have to ensure that all legal and regulatory requirements are satisfied and would be required to obtain the consent of the lenders under Zargon's current syndicated credit facility.

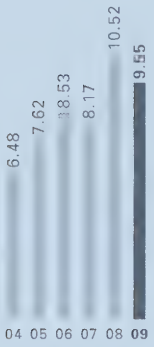
Through to the 2010 renewal, it is anticipated that Zargon's borrowing costs will be higher as general debt pricing, standby fees and extension fees have risen considerably in the current economic environment. Interest rates fluctuate under the syndicated facilities with Canadian prime, US prime and US base rates plus an applicable margin between 125 basis points and 275 basis points (2008 – zero and 32.5 basis points, respectively), as well as with Canadian banker's acceptance and LIBOR rates plus an applicable margin between 275 basis points and 425 basis points (2008 – 97.5 and 157.5 basis points, respectively).

At December 31, 2009, $76.58 million (December 31, 2008 - $77.58 million) had been drawn on the syndicated committed credit facilities with any unused amounts subject to standby fees. The net change in bank debt was nominal, as any requirements to borrow for Zargon's general corporate purposes and corporate and property acquisitions were offset by Zargon's June 2009 equity issuance of trust units.

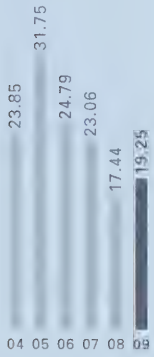
In the normal course of operations, Zargon enters into various letters of credit. At December 31, 2009, the approximate value of outstanding letters of credit totalled $0.61 million (December 31, 2008 - $0.52 million).

Zargon's debt net of working capital (excluding unrealized risk management assets/liabilities and future income taxes) of $88.01 million at December 31, 2009 was equivalent to 102 percent of the 2009 funds flow from operating activities of $86.35 million. At December 31, 2008, the debt net of working capital (excluding unrealized risk management assets/liabilities and future income taxes) was $87.71 million, equivalent to 82 percent of the 2008 funds flow from operating activities of $106.91 million.

**Unitholders' Equity**
*($/unit)*




**Zargon Year End Trust Unit Price**
*($/unit)*




### Equity

At March 9, 2010, Zargon Energy Trust had 23.219 million trust units and 1.768 million exchangeable shares outstanding. Assuming full conversion of exchangeable shares at the effective March 9, 2010 exchange ratio of 1.66788, there would be 26.168 million trust units outstanding. Pursuant to the trust unit rights incentive plans, there are currently an additional 1.440 million trust unit incentive rights issued and outstanding.

During 2009, 12.047 million Zargon trust units traded on the Toronto Stock Exchange with a high trading price of $19.33 per unit, a low of $13.05 per unit and a closing price of $19.25 per unit. The 2009 trading statistics show a 20 percent year-over-year decrease in trading volume and a 10 percent increase in the closing unit price. Zargon's market capitalization (including the market value of exchangeable shares) at year end 2009, was approximately $501 million, compared to approximately $369 million at the end of 2008.

### Segmented Geographic Information

During 2009, approximately 90 percent (2008 – 88 percent) of Zargon's combined petroleum and natural gas revenue came from Western Canadian (Alberta, Saskatchewan and Manitoba) properties, with the remaining 10 percent (2008 – 12 percent) of revenues generated in the United States (North Dakota). This shift in weighting is due to additional revenues generated from the Masters and Churchill corporate acquisitions which both were comprised of only Canadian oil and natural gas properties.

## OFF BALANCE SHEET ARRANGEMENTS

The Trust has no guarantees or off balance sheet arrangements, except for letters of credit which have been issued in the normal course of business of approximately $0.61 million as at December 31, 2009.

## RELATED PARTY TRANSACTIONS

During the year, the Trust paid $0.05 million (2008 – $0.05 million) for vehicle leases to a company owned by a Board member and $0.41 million (2008 – $0.23 million) for legal services to a law firm in which a Board member is a partner. All amounts were based on normal commercial terms and conditions.

## CONTRACTUAL OBLIGATIONS

Zargon has certain contractual obligations relating to the lease of head office space and natural gas transportation sales contracts that extend for longer than one year as set out in the table below:

| ($ millions) | Total | 2010 | 2011 to 2012 | 2013 to 2014 | Thereafter |
|---|---|---|---|---|---|
| Head office lease and other | 4.13 | 2.10 | 2.03 | - | - |
| Natural gas transportation sales contracts | 0.94 | 0.85 | 0.09 | - | - |
| Total | 5.07 | 2.95 | 2.12 | - | - |

## CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements, in accordance with Canadian generally accepted accounting principles, requires management to make judgments and estimates that affect the financial results of the Trust. Zargon's management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. The critical estimates are discussed below:

### Petroleum and Natural Gas Reserves

All of Zargon's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The estimation of reserves is a subjective process. Forecasts are based

on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Trust expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices.

### Full Cost Accounting

Zargon follows the full cost method of accounting for petroleum and natural gas operations as outlined in Canadian Institute of Chartered Accountants ("CICA") accounting guideline "Oil and Gas Accounting – Full Cost" (AcG-16). Under this accounting method, all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Capitalized costs, as well as the estimated future expenditures to develop proved reserves, are depleted using the unit-of-production method based on estimated proved oil and natural gas reserves.

In applying the full cost method, Zargon calculates a ceiling test on a quarterly basis to ensure that the net carrying value of petroleum and natural gas assets does not exceed the estimated undiscounted future net cash flow from production of proved reserves. Accordingly, the Trust must base this calculation of future net cash flow on estimated forecasted sales prices, costs and regulations in effect at the period end. AcG-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flow from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate.

### Asset Retirement Obligations

Zargon follows CICA Section 3110, "Asset Retirement Obligations", which requires liability recognition for retirement obligations associated with the Trust's property, plant and equipment. Under this policy, the Trust is required to provide for future removal and site restoration costs. The Trust must estimate these costs in accordance with existing laws, contracts or other policies and must also estimate a credit adjusted risk-free rate and inflation rate in this calculation. These estimated costs are charged to earnings and the appropriate liability account over the expected life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

### Income Tax Accounting

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

## RECENT AND FUTURE CANADIAN ACCOUNTING PRONOUNCEMENTS

On January 1, 2009, the Trust adopted the CICA Handbook Section 3064 "Goodwill and Intangible Assets", replacing Section 3062 "Goodwill and Other Intangible Assets". Under this new guidance, fewer items meet the criteria for capitalization. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Requirements concerning goodwill are unchanged from the requirements included in the previous Section 3062, as the new Section was only amended for intangible assets. The adoption of this Section did not significantly impact the Trust's consolidated financial statements.

Effective January 1, 2009, the Trust retrospectively adopted the recommendations of Emerging Issues Committee abstract 173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities", which was issued in January 2009, without restatement of prior periods. The abstract requires that an entity's own credit risk and the credit risk of the counterparty are taken into account in determining the fair value of financial assets and liabilities, including derivative instruments, for presentation and

disclosure purposes. The adoption of the abstract did not significantly impact the Trust's consolidated financial statements.

Effective December 31, 2009, the Trust prospectively adopted the CICA amendments to Handbook Section 3855, "Financial Instruments – Recognition and Measurement." Amendments to this Section have prohibited the reclassification of a financial asset out of the held-for-trading category when the fair value of the embedded derivative in a combined contract cannot be reasonably measured.

Section 3855 was also amended with regards to the impairment of financial assets. The definition of "loans and receivables" has been revised and, provided that certain conditions have been met, the amendments permit reclassification of financial assets from the held-for-trading and available-for-sale categories into the loans and receivables category. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. The adoption of the amendments to this standard did not have an impact on the Trust's consolidated financial statements.

Effective December 31, 2009, the Trust adopted CICA issued amendments to Handbook Section 3862, "Financial Instruments – Disclosures." The amendments include enhanced disclosures relating to the fair value of financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. Refer to Note 12 for enhanced fair value disclosures. The amendments are consistent with recent amendments to financial instrument disclosure standards in International Financial Reporting Standards.

In addition, the Trust has assessed new and revised accounting pronouncements that have been issued but are not yet effective and determined the following may have a significant impact on the Trust:

In December 2008, the CICA issued Section 1582 "Business Combinations", which will replace CICA Section 1581 of the same name. Under this guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at the market price on the date of the exchange. Currently, the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all acquisition costs to be expensed, which currently are capitalized as part of the purchase price. Contingent liabilities are to be recognized at fair value at the acquisition date and remeasured at fair value through earnings each period until settled. Currently, only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from the non-current assets in the purchase price allocation. Section 1582 will be effective for the Trust on January 1, 2011, with prospective application. The Trust is currently evaluating the impact of the adoption of the new Section on its consolidated financial statements.

In December 2008, the CICA issued Sections 1601 "Consolidated Financial Statements" and 1602 "Non-controlling Interests", which replaces existing guidance under Section 1600 "Consolidated Financial Statements". Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards will be effective for the Trust on January 1, 2011. Section 1602 will result in the reclassification of non-controlling interest to unitholders' equity. The Trust is currently evaluating the impact of the adoption of Section 1601 on its consolidated financial statements.

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, the AcSB confirmed in February 2008 that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Zargon for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

Zargon's IFRS project consists of three key phases:

- Scoping and diagnostic phase – this phase involves performing a high level impact analysis to identify areas that may be affected by the transition to IFRS.

- Impact analysis and evaluation phase – this phase involves analysis of policy choices allowed under IFRS and their impact on the financial statements.

- Implementation phase – involves implementation of all changes approved in the impact analysis phase and will include changes to information systems, business processes, modification of agreements (if applicable) and training of all staff who are impacted by the conversion.

Zargon has completed the scoping and diagnostic phase and has prepared draft analysis for the impact analysis and evaluation phase. Management has not yet finalized its accounting policies and as such is unable to quantify the impact of adopting IFRS on the consolidated financial statements. In addition, due to anticipated changes to IFRS prior to Zargon's adoption of IFRS, management's plan is subject to change based on new facts and circumstances that arise after the date of this Annual Financial Report.

IFRS 1 "First-Time Adoption of International Financial Reporting Standards" ("IFRS 1"), provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS. Management is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate for Zargon. Zargon currently anticipates utilizing the following IFRS 1 exemptions:

- Property, Plant and Equipment ("PP&E") – IFRS 1 provides the option to value the PP&E assets at their deemed cost being the Canadian GAAP net book value assigned to these assets as at the date of transition, January 1, 2010. This amendment is permissible for entities that currently follow the full cost accounting guideline under Canadian GAAP. Under this current policy, Zargon accumulates all oil and gas assets into separate cost centres for Canada and the United States. Under IFRS, Zargon's PP&E assets must be divided into smaller cost centres. The net book value of the assets on the date of transition will be allocated to the new cost centres on the basis of Zargon's reserve volumes or values at that point in time.

- Business Combinations – IFRS 1 allows Zargon to use the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations. The IFRS business combination rules converge with the new CICA Handbook Section 1582 that is also effective for Zargon on January 1, 2011; however, early adoption is permitted.

The transition from Canadian GAAP to IFRS is a significant undertaking that may materially affect our reported financial position and results of operations. At this time, Zargon has identified key differences that will impact the financial statements as follows:

- Re-classification of Exploration and Evaluation ("E&E") expenditures from PP&E – Upon transition to IFRS, Zargon will re-classify all E&E expenditures that are currently included in the PP&E balance on the consolidated balance sheets. This will consist of the book value for Zargon's undeveloped land that relates to exploration areas. It is not anticipated that E&E assets will be depleted and the assets must be assessed for impairment when indicators of impairment exist.

- Calculation of depletion expense for PP&E assets – Upon transition to IFRS, Zargon has the option to calculate depletion using a reserve base of proved reserves, which is comparable to the Canadian GAAP method of calculation depletion, or both proved and probable reserves. Zargon has not concluded at this time which method for calculating depletion will be used. Also, depletion must be calculated at a more granular level than what is currently required under Canadian GAAP.

- Impairment of PP&E assets – Under IFRS, impairment of PP&E must be calculated at a more granular level than what is currently required under Canadian GAAP. Impairment calculations will be performed at the cash generating unit ("CGU") level using either total proved or proved plus probable reserves. The most significant difference is that the Canadian GAAP "ceiling test" incorporates a 2-step approach for testing impairment, while IFRS uses a 1-step approach. Under Canadian GAAP, a discounted cash flow

analysis is not required if the undiscounted cash flows from proved reserves exceed its carrying amount (step1). If the carrying amount exceeds the undiscounted future cash flows, then a prescribed discounted cash flow test is performed (step 2). Under IFRS, impairment testing based on discounted cash flows or fair value determinations is required and is performed at the CGU level.

- Due to the recent withdrawal of the exposure draft on International Accounting Standards ("IAS") 12 "Income Taxes" in November 2009 and the issuance of the exposure draft on IAS 37 "Provisions, Contingent Liabilities and Contingent Assets" in January 2010, management is still determining the impact of these revised standards on its IFRS transition.

In addition to accounting policy differences, Zargon's transition to IFRS will impact the internal controls over financial reporting ("ICFR") and information technology systems as follows:

- ICFR – As the review of Zargon's accounting policies is completed, an assessment will be made to determine changes required for ICFR. This will be an ongoing process through 2010 to ensure that all changes in accounting policies include the appropriate additional controls and procedures for future IFRS reporting requirements.

- Information technology systems – Zargon will be upgrading systems during the first quarter of 2010 in preparation for IFRS reporting. These modifications are deemed critical in order to allow for reporting of both Canadian GAAP and IFRS financial statements in 2010. Additional system modifications may be required based on final policy choices.

### Design and Evaluation of Internal Control over Financial Reporting and Disclosure Controls and Procedures

Zargon is required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings" and is required to make specific disclosures with respect to NI 52-109. These disclosures can be summarized as follows:

- The President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer have directed an evaluation of Disclosure Control and Procedures ("DC&P") and have concluded that DC&P are designed appropriately and are operating effectively as at December 31, 2009.
- The President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer have directed an evaluation of Internal Controls over Financial Reporting ("ICFR") and have concluded that ICFR are designed appropriately and are operating effectively as at December 31, 2009.
- Zargon reports that no changes were made to ICFR during 2009 that have materially affected, or are reasonably likely to materially affect the Trust's ICFR.
- Zargon has no interests in proportionately consolidated entities or variable interest entities other than Oil and Gas Joint Ventures. Accordingly, the scope of the design of DC&P and ICFR have not been limited to exclude controls, policies and procedures with respect to proportionately consolidated entities or variable interest entities.
- Zargon has not limited the scope of the design of DC&P and ICFR with respect to any businesses acquired in 2009.

Because of their inherent limitations, DC&P and ICFR may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well designed or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

## BUSINESS RISKS AND OUTLOOKS

### Business Risks

Zargon's external business risks arise from the uncertainty of oil and natural gas pricing, the uncertainty of interest and exchange rates, environmental and safety issues and financial and liquidity considerations. Additional risks arise from the production performance of existing properties (including natural decline), the changes in tax, royalty and other regulatory standards and uncertain results from capital expenditure programs.

Oil and natural gas prices may fluctuate widely in response to many factors, such as global and North American supply and demand, economic conditions, weather conditions, political stability, the supply and price of imported oil and liquefied natural gas, production and storage levels of North American natural gas and government regulations. Zargon attempts to minimize pricing and currency exchange uncertainty with a risk management program that encompasses a variety of financial instruments. These could include forward sales of oil and natural gas production (either through financial derivative transactions such as swaps or by physical contracts), put options on both oil and natural gas, costless collars (in which some potential high price gain is given up in return for potential low price support) and US dollar currency risk management transactions in different forms for up to 30 percent of its combined oil and natural gas working interest production volumes. In general, the Trust seeks to use strategies that allow minimum price expectations to be met in order that distributions and capital programs can be funded. This strategy is designed mainly to protect the Trust against periods of unusually low commodity prices and, by its nature, is likely to produce significant risk management losses when prices are unusually high.

Environmental and safety risks are mitigated through compliance with provincial and federal environmental and safety regulations by maintaining adequate insurance and by adopting appropriate emergency response and employee safety procedures.

The Trust is subject to a broad range of laws and regulatory requirements. Changes in government regulations, including reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates can have a significant impact on Zargon. Although Zargon has no control over these regulatory risks, the Trust actively monitors changes, participates in industry organizations and, when required, engages the assistance of third party experts to assess the impact of such changes on the Trust's financial and operating results.

Financial and liquidity risks are reduced by limiting debt financing to self-imposed debt to funds flow guidelines. Zargon maintains a low cash distribution to funds flow from operating activities ratio to ensure funding is available for capital programs to sustain per unit production and reserves. Access to capital markets, if required for additional financing by either debt or equity issuances, is dependent upon maintaining strong performance and relationships with investors. A substantial portion of the Trust's accounts receivable are with companies in the oil and gas industry and are subject to normal industry credit risks. Management regularly monitors the aging of receivable balances to mitigate this risk. With respect to financial instruments utilized for risk management purposes, the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

Changes to the Canadian income trust tax rules after 2010 and the Alberta government's January 1, 2009 royalty changes may have negatively impacted the Canadian oil and gas trust industry's access to new capital from debt and equity markets in the future.

Recent global credit issues may also have negatively impacted overall access to new capital from debt and equity markets in the future. Management believes that the 2009 amendments to its credit facilities provide Zargon reasonable capacity for its operations.

Zargon actively manages the risks of its capital programs and reserves by concentrating drilling and subsequent development activities in areas where it has demonstrated proven technical capabilities and understanding. Zargon's capital budget is managed to limit exposure so that significant capital is not risked on any one project or concept.

### Environmental Regulation and Risk

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases.

In 2008 the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as "ecoACTION", which includes the Regulatory Framework for Air Emissions, and the Alberta Government has also introduced legislation regarding greenhouse gas emissions.

On March 8, 2007, the Alberta government introduced legislation to reduce greenhouse gas emission intensity. Bill 3 states that facilities emitting more than 100,000 tonnes of greenhouse gases per year must reduce their emissions intensity by 12 percent over the average emissions levels of 2003, 2004 and 2005; if they are not able to do so, these facilities will be required to pay $15 per tonne for every tonne above the 12 percent target, beginning on July 1, 2007. At this time, the Trust has determined that there is currently no impact of this legislation on Zargon's existing facilities ownership.

Although Zargon is not a large emitter of greenhouse gases, the Trust continues to monitor developments in this area. Although environmental legislation is evolving in a manner which could result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs, at this time it is not possible to predict the impact of these requirements on the Trust and its operations and financial condition.

### Alberta Royalty and Tax Regime

On February 16, 2007, the Alberta Government announced that a review of the Province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil and gas resources, including oil sands, conventional oil and gas and coalbed methane, would be conducted by a panel of experts with the assistance of individual Albertans and key stakeholders. On September 18, 2007, the Royalty Review Panel delivered its final report and recommendations to the Government of Alberta. The report titled "Our Fair Share", recommended significant increases to royalties levied on natural gas, conventional oil and oil sands produced in Alberta. On October 25, 2007, the Alberta Government released details of its planned implementation of the final Royalty Review Panel report, titled "The New Royalty Framework" ("NRF") which took effect on January 1, 2009. Zargon has now operated for one year under the NRF royalty program and provides the following observations:

- Approximately 30 percent of Zargon's production is from properties located outside Alberta and is therefore not affected by the NRF.
- Royalties determined under the NRF are determined based on commodity prices, well productivity and depth of wells. A significant portion of Zargon's wells are lower productivity wells that were not negatively impacted by the NRF.
- The NRF negatively impacted the economics of Zargon's exploration programs that targeted moderate rate natural gas wells in our West Central Alberta and Alberta Plains core areas. Although, at the recent lower commodity price levels, the impact of the NRF was not significant.

On March 3, 2009, the Government of Alberta announced an incentive program to stimulate new and continued economic activity in Alberta, which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. The new well incentive program applies to wells commencing production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum five percent royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. On June 25, 2009, the

Government of Alberta extended this incentive program by one year to March 31, 2011. The Trust adjusted portions of its capital program to take advantage of this program.

### Outlook

With a strong balance sheet, our ability to execute accretive asset and/or corporate acquisitions, 540 thousand net acres of undeveloped land and a promising oil and natural gas exploitation project inventory, Zargon continues to be well positioned to meet its value-creating objectives in 2010 and beyond. At this time, in early March 2010, future commodity markets have improved from their 2009 lows during a time when our industry's input costs have declined from their historic highs, thereby permitting improved capital program efficiencies and strong economic returns.

Although the last year's world-wide economic crisis, depressed commodity prices, changes to the Canadian income trust tax rules after 2010 and the Alberta Government's 2009 royalty changes have negatively impacted our industry, we are optimistic about Zargon's long term value-seeking strategy in this evolving business. Consistent with its history, Zargon will continue to adhere to its partial cash flow distribution model with a focused oil and natural gas exploitation strategy augmented by accretive acquisitions, which will be funded by debt or equity issuances.

## SELECTED QUARTERLY INFORMATION

| ($ millions, except per unit amounts) | 2009 | | | | 2008 | | | |
|---|---|---|---|---|---|---|---|---|
| | **Q4** | **Q3** | **Q2** | **Q1** | Q4 | Q3 | Q2 | Q1 |
| Petroleum and natural gas revenue | **47.21** | **40.96** | **35.84** | **31.98** | 41.25 | 66.35 | 69.66 | 52.24 |
| Funds flow from operating activities | **24.75** | **22.84** | **20.92** | **17.85** | 20.40 | 29.75 | 32.02 | 24.75 |
| Per unit – diluted | **0.95** | **0.90** | **0.91** | **0.84** | 0.97 | 1.42 | 1.55 | 1.23 |
| Cash flows from operating activities | **27.86** | **23.30** | **21.94** | **15.73** | 24.84 | 33.58 | 36.44 | 15.27 |
| Per unit – diluted | **1.07** | **0.92** | **0.95** | **0.74** | 1.18 | 1.60 | 1.76 | 0.76 |
| Net earnings | **0.44** | **4.47** | **(2.55)** | **0.37** | 28.19 | 40.05 | (4.51) | 4.56 |
| Per unit – diluted | **0.02** | **0.20** | **(0.13)** | **0.02** | 1.53 | 2.20 | (0.25) | 0.26 |
| Cash distributions | **12.45** | **12.22** | **11.26** | **10.03** | 9.96 | 9.87 | 9.71 | 9.55 |
| Per unit – diluted | **0.54** | **0.54** | **0.54** | **0.54** | 0.54 | 0.54 | 0.54 | 0.54 |
| Net capital expenditures | **12.87** | **29.32** | **48.96** | **13.44** | 16.37 | 17.47 | 26.28 | 59.61 |
| Total assets | **464.38** | **473.47** | **466.60** | **440.76** | 447.60 | 426.63 | 418.88 | 396.90 |
| Bank debt | **76.58** | **77.05** | **70.43** | **85.78** | 77.58 | 74.95 | 85.45 | 92.18 |

## FOURTH QUARTER 2009 RESULTS

During the fourth quarter of 2009, Zargon's petroleum and natural gas revenues of $47.21 million were 15 percent higher than the previous quarter's revenues. Production for the 2009 fourth quarter of 10,586 barrels of oil equivalent per day was five percent higher than the 2009 third quarter's production of 10,088 barrels of oil equivalent per day. Compared to the previous quarter, oil production increased two percent to 5,485 barrels per day as flush production was recognized from the tie-in of Williston Basin oil wells and from volumes gained from the acquisition of Churchill Energy Inc. being included for the full quarter. Fourth quarter natural gas production increased eight percent from the previous quarter to 30.60 million cubic feet per day as various shut-in wells were reactivated and due to the initial production rates from new natural gas in the Kakut area of West Central Alberta along with additional volumes recognized from the late 2009 third quarter acquisition of Churchill. Average field prices received during the fourth quarter, before the impact of financial risk management contracts, were $68.88 per barrel for oil and liquids and $4.42 per thousand cubic feet for natural gas, a six percent and a 29 percent increase, respectively, compared to the 2009 third quarter prices. Zargon's field price differential for its blended 30 degree API crude oil stream increased to a $7.68 per barrel discount to the Edmonton reference crude oil price, a 32 percent increase from Zargon's average differential of $5.80 per barrel for the first nine months of 2009.

Funds flow from operating activities was $24.75 million in the fourth quarter, an increase of eight percent or $1.91 million from the prior quarter. A comparative analysis of the primary factors that caused this quarter-over-quarter increase is as follows:

- Fourth quarter 2009 petroleum and natural gas revenues of $47.21 million were 15 percent higher than the 2009 third quarter revenues of $40.96 million. This revenue increase was a result of the 10 percent increase in average realized commodity prices and a five percent increase in average daily production volumes.
- Realized risk management gains were $5.78 million in the fourth quarter of 2009, a $1.05 million decrease from the prior quarter's $6.83 million of realized risk management gains. The quarter over quarter decrease, resulted from risk management contract expiries and increasing commodity prices. The fourth quarter net gains resulted from gains ($0.42 million) being realized on financial natural gas risk management contracts, gains ($5.38 million) realized on financial oil risk management contracts (foreign exchange contracts are considered in conjunction with the oil contracts) and losses ($0.02 million) realized on financial electricity management contracts. Oil and natural gas prices continued to strengthen during the 2009 fourth quarter.
- Royalties for the fourth quarter were $8.27 million, an increase of $0.71 million from the prior quarter. The average royalty rate for the quarter of 17.5 percent was below the 18.5 percent rate from the 2009 third quarter, as a result of additional low rate incentive wells, which were brought on production and some prior period adjustments.
- Production expenses were $12.75 million for the quarter, four percent higher than the third quarter of 2009. On a per barrel of oil equivalent basis, production expenses decreased one percent to $13.09 in the fourth quarter of 2009 compared to $13.18 in the prior quarter. This quarterly decline in per unit costs was due, in part, to increased production from new wells being tied-in, the reactivation of gas wells and initial production rates from new gas wells.
- General and administrative expenses increased in the fourth quarter by $0.75 million over the third quarter of 2009. This is a 25 percent increase compared to the prior quarter and is primarily due to amounts recorded for the year end performance-based compensation for employees.
- Interest and financing charges in the fourth quarter were $1.10 million, an increase of 38 percent or $0.30 million from the prior quarter. The average debt level for the fourth quarter increased 12 percent to $87.06 million compared to $77.56 million in the third quarter of 2009, resulting in increased debt

servicing charges. Zargon's interest borrowing rates also increased during the quarter in-line with the borrowing pricing grid established under the terms of Zargon's credit facilities.

- Current income taxes of $0.91 million were $0.23 million higher than the 2009 third quarter taxes. The increase was primarily due to increased withholding taxes on dividends declared from Zargon's US subsidiary to its parent corporation.
- Asset retirement expenditures reflect the actual amounts incurred to abandon and reclaim unutilized non-producing wells. These asset retirement expenditures totalled $1.49 million in the 2009 fourth quarter and increased from the prior quarter amount of $0.69 million. The difference between accretion expenses (as reflected on the income statements) and asset retirement expenditures are a result of the timing differences between the estimating of future expenses and the incurrence of actual expenses during the period.

Net earnings for the quarter decreased $4.03 million to $0.44 million, a 90 percent decrease compared to the third quarter of 2009 net earnings of $4.47 million. Net earnings track the funds flow from operating activities for the respective periods modified by asset retirement expenditures and non-cash charges, which included the following for the fourth quarter of 2009:

- Unit-based compensation expense increased by $0.05 million during the fourth quarter of 2009 to $0.44 million, a 13 percent increase from the third quarter. The increase is a result of additional unit rights granted in the fourth quarter of 2009.
- Depletion and depreciation expense increased by $0.69 million to $17.50 million in the 2009 fourth quarter. The additional expense resulted from the increased production in the fourth quarter despite the use of an updated depletion and depreciation rate of $17.97 per barrel of oil equivalent, compared to the prior quarter's $18.12 per barrel of oil equivalent charge.
- Unrealized risk management losses in the 2009 fourth quarter of $12.97 million were 261 percent higher than the third quarter losses of $3.60 million. These unrealized losses result from "marking-to-market" financial risk management contracts at each period end. During the fourth quarter, unrealized risk management losses resulted from higher commodity pricing at the December 31, 2009 mark-to-market date when compared to the third quarter September 30, 2009 mark-to-market date. In particular, higher year end futures resulted in unrealized risk management contract oil losses of $11.31 million, natural gas contract losses of $0.42 million, electricity contract losses of $0.13 million and foreign exchange contract losses of $1.11 million. The realization and the expiry of certain financial natural gas and oil contracts also affect the mark-to-market amounts.
- The provision for accretion of asset retirement obligations for the 2009 fourth quarter was $0.75 million, relatively even with the prior quarter expense. The small quarter-over-quarter increase is due to changes in the estimated future liability for asset retirement obligations as a result of wells added through Zargon's drilling program inclusive of wells acquired/disposed of in the quarter and changes resulting from revisions to the timing and the amounts of the original estimates of undiscounted cash flows.
- Unrealized foreign exchange losses of $0.05 million in the 2009 fourth quarter compare to losses of $0.08 million for the prior quarter. Gains and losses result from translations of Zargon's US subsidiaries into Canadian dollars at rates as determined under the temporal method of converting foreign subsidiaries as required by Canadian GAAP. Relative to the closing foreign exchange rates at September 30, 2009, the increase in the value of the Canadian dollar relative to the US dollar has created nominal non-cash translation losses as recorded in Zargon's income statement for the fourth quarter.
- The future income tax recovery was $5.98 million during the quarter compared to a future income tax recovery of $3.13 million from the third quarter of 2009. The increased future income tax recovery in the 2009 fourth quarter was due to a significant increase of losses before taxes of $4.58 million compared to the third quarter earnings before taxes of $2.59 million. In summary, the fourth quarter

losses before taxes were primarily a result of higher non-cash unrealized risk management contract losses in the quarter.

- Reduction in earnings due to non-controlling interests pertaining to exchangeable shares decreased to $0.06 million in the 2009 fourth quarter from $0.57 million in the third quarter. This was due to a decrease in net earnings before non-controlling interest in the fourth quarter.

Net capital expenditures were $12.87 million during the fourth quarter of 2009, a 56 percent decrease from the prior quarter amount of $29.32 million (which included $16.31 million for the Churchill acquisition). During the fourth quarter, Zargon completed a field capital program focused on the Alberta Plains core area Taber oil exploitation wells, a West Central Alberta natural gas exploration location and the Williston Basin core area horizontal oil exploitation wells. During the fourth quarter of 2009, 5.0 net wells (Williston Basin – 1.8 net wells, Alberta Plains – 3.0 net wells, West Central Alberta – 0.2 net wells) were drilled compared to 10.3 net wells in the third quarter of 2009.

Cash distributions to unitholders declared for the 2009 fourth quarter totalled $12.45 million ($0.18 per trust unit per month).

## ADDITIONAL INFORMATION

Additional information regarding the Trust and its business operations, including the Trust's Annual Information Form for December 31, 2009, is available on the Trust's SEDAR profile at www.sedar.com.

# MANAGEMENT'S REPORT

The consolidated financial statements of Zargon Energy Trust were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the financial statements reliably report the Trust's operations and that the Trust's assets are safeguarded. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

Ernst & Young LLP, an independent chartered accountant firm, was appointed by a resolution of the unitholders to audit the consolidated financial statements of the Trust and provide an independent opinion. They have conducted an independent examination of the Trust's accounting records in order to express their opinion on the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management directors, has met with Ernst & Young LLP and management in order to determine that management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Audit Committee has reported its findings to the Board of Directors, who have approved the consolidated financial statements.

**C.H. Hansen**
President and Chief Executive Officer

**B.C. Heagy**
Executive Vice President and
Chief Financial Officer

Calgary, Canada
March 9, 2010

# AUDITOR'S REPORT

To the Unitholders of **Zargon Energy Trust**

We have audited the consolidated balance sheets of Zargon Energy Trust as at December 31, 2009 and 2008 and the consolidated statements of earnings and comprehensive income and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2009 and 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Calgary, Canada
March 9, 2010

Chartered Accountants

# CONSOLIDATED BALANCE SHEETS

| As at December 31 ($ thousands) | 2009 | 2008 |
|---|---|---|
| **ASSETS** [note 6] | | |
| **Current** | | |
| Accounts receivable | **25,223** | 20,725 |
| Prepaid expenses and deposits | **2,013** | 1,162 |
| Unrealized risk management asset [note 12] | **4,289** | 29,641 |
| Future income taxes [note 13] | **1,714** | – |
| | **33,239** | 51,528 |
| **Long term deposit** | **1,845** | 1,612 |
| **Unrealized risk management asset** [note 12] | **–** | 4,745 |
| **Goodwill** | **2,969** | 2,969 |
| **Property and equipment, net** [notes 4 and 5] | **425,964** | 386,746 |
| **Future income taxes** [note 13] | **361** | – |
| | **464,378** | 447,600 |
| **LIABILITIES** | | |
| **Current** | | |
| Accounts payable and accrued liabilities | **34,507** | 28,687 |
| Cash distributions payable [note 19] | **4,157** | 3,326 |
| Unrealized risk management liability [note 12] | **6,032** | 724 |
| Future income taxes [note 13] | **1,219** | 8,553 |
| | **45,915** | 41,290 |
| **Long term debt** [note 6] | **76,580** | 77,581 |
| **Unrealized risk management liability** [note 12] | **1,270** | 281 |
| **Asset retirement obligations** [note 7] | **35,468** | 28,592 |
| **Future income taxes** [note 13] | **30,327** | 49,704 |
| | **189,560** | 197,448 |
| **Commitments and contingencies** [notes 6, 8, 12, 14 and 15] | | |
| **NON-CONTROLLING INTEREST** | | |
| Exchangeable shares [note 9] | **26,477** | 27,610 |
| **UNITHOLDERS' EQUITY** | | |
| Unitholders' capital [note 8] | **188,840** | 120,650 |
| Contributed surplus [note 8] | **5,471** | 4,617 |
| Accumulated earnings | **259,823** | 257,104 |
| Accumulated cash distributions [note 19] | **(205,793)** | (159,829) |
| | **248,341** | 222,542 |
| | **464,378** | 447,600 |

*See accompanying notes to the consolidated financial statements.*

On behalf of the Board:

K.J. Harrison, Director

K.D. Kitagawa, Director

# CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME AND ACCUMULATED EARNINGS

| For the years ended December 31 ($ thousands, except per unit amounts) | 2009 | 2008 |
|---|---|---|
| **REVENUE** | | |
| Petroleum and natural gas revenue | **155,985** | 229,494 |
| Unrealized risk management gain/(loss) [note 12] | **(36,393)** | 44,378 |
| Realized risk management gain/(loss) [note 12] | **27,685** | (15,722) |
| Royalties | **(27,422)** | (46,644) |
| | **119,855** | 211,506 |
| **EXPENSES** | | |
| Production | **47,564** | 39,913 |
| General and administrative | **13,769** | 10,447 |
| Unit-based compensation [note 8] | **1,263** | 1,185 |
| Interest and financing charges [note 6] | **3,015** | 4,911 |
| Unrealized foreign exchange (gain)/loss | **184** | (1,958) |
| Accretion of asset retirement obligations [note 7] | **2,744** | 2,183 |
| Depletion and depreciation | **64,715** | 59,638 |
| | **133,254** | 116,319 |
| **EARNINGS/(LOSSES) BEFORE INCOME TAXES** | **(13,399)** | 95,187 |
| **INCOME TAXES** [note 13] | | |
| Current | **2,492** | 4,051 |
| Future tax expense/(recovery) | **(18,947)** | 12,751 |
| | **(16,455)** | 16,802 |
| **EARNINGS BEFORE NON-CONTROLLING INTEREST** | **3,056** | 78,385 |
| Non-controlling interest – exchangeable shares [note 9] | **(337)** | (10,100) |
| **NET EARNINGS AND COMPREHENSIVE INCOME** | **2,719** | 68,285 |
| **ACCUMULATED EARNINGS, BEGINNING OF YEAR** | **257,104** | 188,819 |
| **ACCUMULATED EARNINGS, END OF YEAR** | **259,823** | 257,104 |
| **NET EARNINGS PER UNIT** [note 10] | | |
| Basic | **0.13** | 3.79 |
| Diluted | **0.13** | 3.80 |

*See accompanying notes to the consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| For the years ended December 31 ($ thousands) | 2009 | 2008 |
|---|---|---|
| **OPERATING ACTIVITIES** | | |
| Net earnings for the year | **2,719** | 68,285 |
| Add (deduct) non-cash items: | | |
| Non-controlling interest – exchangeable shares | **337** | 10,100 |
| Unrealized risk management (gain)/loss | **36,393** | (44,378) |
| Depletion and depreciation | **64,715** | 59,638 |
| Accretion of asset retirement obligations | **2,744** | 2,183 |
| Unit-based compensation | **1,263** | 1,185 |
| Unrealized foreign exchange (gain)/loss | **184** | (1,958) |
| Future income tax expense/(recovery) | **(18,947)** | 12,751 |
| Asset retirement expenditures | **(3,056)** | (897) |
| | **86,352** | 106,909 |
| Changes in non-cash operating working capital [note 16] | **2,476** | 3,215 |
| | **88,828** | 110,124 |
| **FINANCING ACTIVITIES** | | |
| Advances/(repayment) of bank debt | **(1,001)** | 3,799 |
| Cash distributions declared to unitholders | **(45,964)** | (39,086) |
| Exercise of unit rights | **1,295** | 1,166 |
| Issuance of unitholders' capital, net of issue costs | **33,444** | – |
| Changes in non-cash financing working capital [note 16] | **831** | 252 |
| | **(11,395)** | (33,869) |
| **INVESTING ACTIVITIES** | | |
| Additions to property and equipment | **(48,382)** | (58,944) |
| Proceeds on disposal of property and equipment | **127** | 220 |
| Corporate acquisitions (cash portion) | **(19,260)** | (16,835) |
| Long term deposit | **(233)** | (157) |
| Changes in non-cash investing working capital [note 16] | **(9,685)** | (539) |
| | **(77,433)** | (76,255) |
| **NET CHANGE IN CASH DURING THE YEAR AND CASH, END OF YEAR** | **–** | – |

*See supplemental cash flow information contained in note 17.*

*See accompanying notes to the consolidated financial statements.*

*December 31, 2009 and 2008*
*All amounts are stated in Canadian dollars unless otherwise noted.*

## 1. STRUCTURE OF THE TRUST

On July 15, 2004, Zargon Oil & Gas Ltd. (the "Company") was reorganized into Zargon Energy Trust (the "Trust" or "Zargon") as part of a Plan of Arrangement (the "Arrangement"). Shareholders of the Company received one trust unit or one exchangeable share for each common share held. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust. Holders of exchangeable shares are not eligible to receive cash distributions paid, but rather, on each payment of a distribution, the number of trust units into which each exchangeable share is exchangeable is increased on a cumulative basis in respect of the distribution. The Trust is an unincorporated open-end investment trust established under the laws of the Province of Alberta and was created pursuant to a trust indenture ("Trust Indenture").

The Trust's principal business activity is the exploration for and development and production of petroleum and natural gas in Canada and the United States ("US").

## 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### Basis of Presentation and Consolidation

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ materially from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies summarized below.

The consolidated financial statements include the accounts of Zargon Energy Trust, all of its subsidiaries and a partnership. All subsidiaries and the partnership are directly or indirectly owned and their operations are fully reflected in the consolidated financial statements.

### Revenue Recognition

Revenue associated with the sale of crude oil, natural gas, and natural gas liquids is recognized when title and risks pass to the purchaser, normally at the plant gate which is the pipeline delivery point for natural gas and at the contracted delivery point for crude oil.

### Joint Operations

A portion of the petroleum and natural gas operations of the Trust are conducted jointly with others, and accordingly, these consolidated financial statements reflect only the proportionate interests of the Trust in such activities.

### Property and Equipment

The Trust follows the full cost method of accounting for its oil and natural gas operations whereby all costs relating to the acquisition, exploration and development of oil and natural gas reserves are capitalized and accumulated in separate cost centres for Canada and the United States. Such costs include land acquisition costs, annual carrying charges of non-producing properties, geological and geophysical costs and costs of drilling and equipping wells.

Depletion and depreciation of petroleum, natural gas properties and equipment is computed using the unit of production method based on the estimated proved reserves of petroleum and natural gas before royalties determined by independent consultants. For purposes of this calculation, reserves are converted to common units on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil. A portion of the cost of petroleum and natural gas rights relating to undeveloped properties is excluded from the depletion calculation. Twenty percent of the year end balance of these costs is added to the depletion base each year. Proceeds on the disposal of petroleum and natural gas properties are applied against capitalized costs, with gains or losses not ordinarily recognized, unless such a disposal would result in a change in the depletion rate of 20 percent or more.

Depreciation of office equipment is provided using the declining balance method at an annual rate of 20 percent. Leasehold improvements are depreciated over the term of the lease.

**Impairment Test**

The Trust applies an impairment test to petroleum, natural gas properties and equipment costs on a quarterly basis or more frequently as events or circumstances dictate. This impairment test is performed on both the Canadian and US cost centres. An impairment loss exists when the carrying amount of the Trust's petroleum, natural gas properties and equipment exceeds the estimated undiscounted future net cash flows associated with the Trust's proved reserves (before royalties). If an impairment loss is determined to exist, the costs carried on the consolidated balance sheets in excess of the fair value of the Trust's proved and probable reserves plus the cost of unproved properties are charged to earnings. Reserves are determined pursuant to evaluation by independent engineers as dictated by National Instrument 51-101.

**Goodwill**

The Trust must record goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired company. The goodwill balance is assessed for impairment annually at year end or as events occur that could result in an indication of impairment. Impairment is recognized based on the fair value of the reporting entity (consolidated Trust) compared to the book value of the reporting entity. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated Trust over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period in which it occurs.

Goodwill is stated at cost less impairment and is not amortized.

At December 31, 2009 an impairment test was performed and it was determined that there was no impairment to the goodwill balance (December 31, 2008 – nil).

**Asset Retirement Obligations**

Zargon recognizes the fair value of an Asset Retirement Obligation ("ARO") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit of production method based on proved reserves (before royalties). The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed in the period. Actual costs incurred upon the settlement of the ARO are charged against the liability.

**Financial Instruments**

All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3855.

Financial assets and financial liabilities classified as "held-for-trading" are measured at fair value with changes in fair value recognized in earnings. Financial assets classified as "available-for-sale" are measured at fair value, with changes in fair value recognized in other comprehensive income ("OCI") until the asset is removed from the consolidated balance sheets. Financial assets classified as "held-to-maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Derivative financial instruments are utilized to reduce commodity price risk associated with the Trust's production of oil and natural gas. The base prices for the commodities are sometimes denominated in US dollars and the Trust may also use such financial instruments to reduce the related foreign currency risk. Financial instruments may also be used from time to time to reduce interest rate risk on outstanding debt. The Trust does not enter into financial instruments for trading or speculative purposes.

The Trust follows a policy of using risk management instruments such as fixed price swaps, forward sales, puts and costless collars. The objective is to partially offset or mitigate the wide price swings commonly encountered in oil and natural gas commodities and in so doing protect a minimum level of cash flow in periods of low commodity prices.

The Trust considers these financial risk management contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and, accordingly, for outstanding contracts not designated as hedges,

an unrealized gain or loss is recorded based on the change in fair value ("mark-to-market") of the contracts at each reporting period end. These instruments have been recorded as unrealized risk management assets/liabilities in the consolidated balance sheets.

In the case of forward sales, the instrument can sometimes be satisfied by physical delivery. In the case of physical delivery, the payment/receipt is recorded as part of the normal revenue stream.

Foreign currency collar and swap agreements are utilized to manage the risk inherent in producing commodities whose price is based directly or indirectly on US dollars, using notional principal amounts equal to the projected monthly revenue from their sale. Payments or charges are calculated and paid according to the terms of the agreement, usually with monthly settlement.

The Trust had no interest rate financial instruments at December 31, 2009 and 2008.

**Income Taxes**

The Trust follows the liability method of tax allocation in accounting for income taxes. Under this method, the Trust records future income taxes for the effect of any differences between the accounting and income tax basis of an asset or liability using income tax rates expected to apply in the periods in which these temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is recognized in earnings in the period in which the change is substantively enacted.

**Foreign Currency Translation**

The Trust uses the temporal method of foreign currency translation whereby the monetary assets and liabilities recorded in a foreign currency are translated into Canadian dollars at year end exchange rates, and non-monetary assets and liabilities at the exchange rates prevailing when the assets were acquired or liability incurred. Revenues and expenses are translated at the average rate of exchange prevailing during the year. Gains and losses on translation are included in the consolidated statements of earnings and comprehensive income and accumulated earnings.

**Trust Unit Rights and Unit-Based Compensation**

Under the Trust's unit rights incentive plans (the "Plans"), rights to purchase trust units are allowed to be granted to directors, officers, employees and other service providers at current market prices. The Plans allow for the exercise price of rights to be reduced in future periods by an amount that distributions exceed a stated return on assets. Under the fair value method of accounting for unit-based compensation, the cost of the option is charged to earnings with an offsetting amount recorded in contributed surplus, based on an estimate from the fair value model. Forfeiture of rights are recorded as a reduction in expense in the period in which they occur if the rights have not yet vested.

**Per Unit Amounts**

Per unit amounts are calculated using the weighted average number of trust units outstanding during the year. Diluted per unit amounts are calculated using the treasury stock method to determine the dilutive effect of unit-based compensation. The Trust follows the treasury stock method, which assumes that the proceeds received from "in-the-money" trust unit rights and unrecognized future unit-based compensation expense are used to repurchase units at the average market rate during the year. Diluted per unit amounts also include exchangeable shares using the "if-converted" method, whereby it is assumed the conversion of the exchangeable shares occurs at the beginning of the reporting period (or at the time of issuance if later).

**Measurement Uncertainty**

The amounts recorded for depletion and depreciation of property and equipment and the assessment of these assets for impairment are based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal and regulatory environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment is made to the property and equipment balance.

**Cash Distributions**

The Trust declares monthly distributions of cash to unitholders of record on the last day of each calendar month. Pursuant to the Trust's policy, it will pay distributions to its unitholders subject to satisfying its financing covenants. Such distributions are recorded as distributions of equity upon declaration of the distribution.

## 3. CHANGES IN ACCOUNTING POLICIES

**Goodwill and Intangible Assets**

On January 1, 2009, the Trust adopted the CICA Handbook Section 3064 "Goodwill and Intangible Assets", replacing Section 3062 "Goodwill and Other Intangible Assets". Under this new guidance, fewer items meet the criteria for capitalization. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Requirements concerning goodwill are unchanged from the requirements included in the previous Section 3062, as the new Section was only amended for intangible assets. The adoption of this Section did not significantly impact the Trust's consolidated financial statements.

**Credit Risk and the Fair Value of Financial Instruments**

Effective January 1, 2009, the Trust retrospectively adopted the recommendations of Emerging Issues Committee abstract 173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities", which was issued in January 2009, without restatement of prior periods. The abstract requires that an entity's own credit risk and the credit risk of the counterparty are taken into account in determining the fair value of financial assets and liabilities, including derivative instruments, for presentation and disclosure purposes. The adoption of the abstract did not significantly impact the Trust's consolidated financial statements.

**Financial Instruments – Recognition and Measurement**

Effective December 31, 2009, the Trust prospectively adopted the CICA amendments to Handbook Section 3855, "Financial Instruments – Recognition and Measurement." Amendments to this Section have prohibited the reclassification of a financial asset out of the held-for-trading category when the fair value of the embedded derivative in a combined contract cannot be reasonably measured.

Section 3855 was also amended with regards to the impairment of financial assets. The definition of "loans and receivables" has been revised and, provided that certain conditions have been met, the amendments permit reclassification of financial assets from the held-for-trading and available-for-sale categories into the loans and receivables category. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. The adoption of the amendments to this standard did not have an impact on the Trust's consolidated financial statements.

**Financial Instruments – Disclosure and Presentation**

Effective December 31, 2009, the Trust adopted CICA issued amendments to Handbook Section 3862, "Financial Instruments – Disclosures." The amendments include enhanced disclosures relating to the fair value of financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. Refer to Note 12 for enhanced fair value disclosures. The amendments are consistent with recent amendments to financial instrument disclosure standards in International Financial Reporting Standards.

**Future Accounting Pronouncements**

In addition, the Trust has assessed new and revised accounting pronouncements that have been issued but are not yet effective and determined the following may have a significant impact on the Trust:

In December 2008, the CICA issued Section 1582 "Business Combinations", which will replace CICA Section 1581 of the same name. Under this guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at the market price on the date of the exchange. Currently, the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all acquisition costs to be expensed, which currently are capitalized as part of the purchase price. Contingent liabilities are to be recognized at fair value at the acquisition date and remeasured at fair value through earnings each period until settled. Currently, only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from the non-current assets in the purchase price allocation. Section 1582 will be effective for the Trust on January 1, 2011, with prospective application. The Trust is currently evaluating the impact of the adoption of the new Section on its consolidated financial statements.

In December 2008, the CICA issued Sections 1601 "Consolidated Financial Statements" and 1602 "Non-controlling Interests", which replaces existing guidance under Section 1600 "Consolidated Financial Statements". Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards will be effective for the Trust on January 1, 2011. Section 1602 will result in the reclassification of non-controlling interest to unitholders' equity. The Trust is currently evaluating the impact of the adoption of Section 1601 on its consolidated financial statements.

**International Financial Reporting Standards**

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, the AcSB confirmed in February 2008 that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Zargon for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

Zargon's IFRS project consists of three key phases:

- Scoping and diagnostic phase – this phase involves performing a high level impact analysis to identify areas that may be affected by the transition to IFRS.

- Impact analysis and evaluation phase – this phase involves analysis of policy choices allowed under IFRS and their impact on the financial statements.

- Implementation phase – involves implementation of all changes approved in the impact analysis phase and will include changes to information systems, business processes, modification of agreements (if applicable) and training of all staff who are impacted by the conversion.

Zargon has completed the scoping and diagnostic phase and has prepared draft analysis for the impact analysis and evaluation phase. Management has not yet finalized its accounting policies and as such is unable to quantify the impact of adopting IFRS on the consolidated financial statements. In addition, due to anticipated changes to IFRS prior to Zargon's adoption of IFRS, management's plan is subject to change based on new facts and circumstances that arise after the date of this Annual Financial Report.

IFRS 1 "First-Time Adoption of International Financial Reporting Standards" ("IFRS 1"), provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS. Management is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate for Zargon. Zargon currently anticipates utilizing the following IFRS 1 exemptions:

- Property, Plant and Equipment ("PP&E") – IFRS 1 provides the option to value the PP&E assets at their deemed cost being the Canadian GAAP net book value assigned to these assets as at the date of transition, January 1, 2010. This amendment is permissible for entities that currently follow the full cost accounting guideline under Canadian GAAP. Under this current policy, Zargon accumulates all oil and gas assets into separate cost centres for Canada and the United States. Under IFRS, Zargon's PP&E assets must be divided into smaller cost centres. The net book value of the assets on the date of transition will be allocated to the new cost centres on the basis of Zargon's reserve volumes or values at that point in time.

- Business Combinations – IFRS 1 allows Zargon to use the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations. The IFRS business combination rules converge with the new CICA Handbook Section 1582 that is also effective for Zargon on January 1, 2011; however, early adoption is permitted.

The transition from Canadian GAAP to IFRS is a significant undertaking that may materially affect our reported financial position and results of operations. At this time, Zargon has identified key differences that will impact the financial statements as follows:

- Re-classification of Exploration and Evaluation ("E&E") expenditures from PP&E – Upon transition to IFRS, Zargon will re-classify all E&E expenditures that are currently included in the PP&E balance on the consolidated balance sheets. This will consist of the book value for Zargon's undeveloped land that relates to exploration areas. It is not anticipated that E&E assets will be depleted and the assets must be assessed for impairment when indicators of impairment exist.

- Calculation of depletion expense for PP&E assets – Upon transition to IFRS, Zargon has the option to calculate depletion using a reserve base of proved reserves, which is comparable to the Canadian GAAP method of calculation depletion, or both proved and

probable reserves. Zargon has not concluded at this time which method for calculating depletion will be used. Also, depletion must be calculated at a more granular level than what is currently required under Canadian GAAP.

- Impairment of PP&E assets – Under IFRS, impairment of PP&E must be calculated at a more granular level than what is currently required under Canadian GAAP. Impairment calculations will be performed at the cash generating unit ("CGU") level using either total proved or proved plus probable reserves. The most significant difference is that the Canadian GAAP "ceiling test" incorporates a 2-step approach for testing impairment, while IFRS uses a 1-step approach. Under Canadian GAAP, a discounted cash flow analysis is not required if the undiscounted cash flows from proved reserves exceed its carrying amount (step1). If the carrying amount exceeds the undiscounted future cash flows, then a prescribed discounted cash flow test is performed (step 2). Under IFRS, impairment testing based on discounted cash flows or fair value determinations is required and is performed at the CGU level.

- Due to the recent withdrawal of the exposure draft on International Accounting Standards ("IAS") 12 "Income Taxes" in November 2009 and the issuance of the exposure draft on IAS 37 "Provisions, Contingent Liabilities and Contingent Assets" in January 2010, management is still determining the impact of these revised standards on its IFRS transition.

In addition to accounting policy differences, Zargon's transition to IFRS will impact the internal controls over financial reporting ("ICFR") and information technology systems as follows:

- ICFR – As the review of Zargon's accounting policies is completed, an assessment will be made to determine changes required for ICFR. This will be an ongoing process through 2010 to ensure that all changes in accounting policies include the appropriate additional controls and procedures for future IFRS reporting requirements.

- Information technology systems – Zargon will be upgrading systems during the first quarter of 2010 in preparation for IFRS reporting. These modifications are deemed critical in order to allow for reporting of both Canadian GAAP and IFRS financial statements in 2010. Additional system modifications may be required based on final policy choices.

## 4. ACQUISITIONS

### Churchill Energy Inc.

On September 23, 2009, a subsidiary of the Trust acquired all of the outstanding shares of Churchill Energy Inc. ("Churchill"), a public oil and gas company, for consideration of $9.74 million. Consideration consisted of $0.11 million cash, the issuance of 554,669 Zargon trust units valued at $16.87 per unit and acquisition costs of $0.27 million.

The results of operations for Churchill have been included in the consolidated financial statements since September 23, 2009.

The acquisition was accounted for by the purchase method and the preliminary purchase price allocation is as follows:

**Net Assets Acquired**

| ($ thousands) | |
|---|---|
| Property and equipment | **9,794** |
| Working capital deficiency | **(6,576)** |
| Future income tax asset | **8,920** |
| Asset retirement obligations | **(2,403)** |
| Total net assets acquired | **9,735** |

**Consideration**

| ($ thousands) | |
|---|---|
| Cash | 108 |
| Trust units issued | 9,357 |
| Acquisition costs | 270 |
| Total purchase price | 9,735 |

**Masters Energy Inc.**

On April 29, 2009, a subsidiary of the Trust acquired all of the outstanding shares of Masters Energy Inc. ("Masters"), a public oil and gas company, for consideration of $27.10 million. Consideration consisted of $5.70 million cash, the issuance of 1,475,468 Zargon trust units valued at $14.26 per unit and acquisition costs of $0.36 million. Zargon assumed Masters' long term debt, which was repaid on the closing date of the acquisition.

The results of operations for Masters have been included in the consolidated financial statements since April 29, 2009.

The acquisition was accounted for by the purchase method and the purchase price allocation is as follows:

**Net Assets Acquired**

| ($ thousands) | |
|---|---|
| Property and equipment | 44,030 |
| Working capital deficiency | (105) |
| Long term debt | (12,825) |
| Future income tax asset | 69 |
| Asset retirement obligations | (4,072) |
| Total net assets acquired | 27,097 |

**Consideration**

| ($ thousands) | |
|---|---|
| Cash | 5,700 |
| Trust units issued | 21,040 |
| Acquisition costs | 357 |
| Total purchase price | 27,097 |

**Newpact Energy Corp.**

On May 16, 2008, a subsidiary of the Trust acquired all of the outstanding shares of Newpact Energy Corp. ("Newpact"), a private oil and gas company, for consideration of $9.54 million. Consideration consisted of the issuance of 425,940 Zargon trust units valued at $22.04 per unit and acquisition costs of $0.15 million.

The results of operations for Newpact have been included in the consolidated financial statements since May 16, 2008.

The acquisition was accounted for by the purchase method and the purchase price allocation is as follows:

**Net Assets Acquired**

| ($ thousands) | |
|---|---|
| Property and equipment | 13,925 |
| Working capital deficiency | (2,491) |
| Future income tax liability | (922) |
| Asset retirement obligations | (976) |
| Total net assets acquired | 9,536 |

**Consideration**

| ($ thousands) | |
|---|---|
| Trust units issued | 9,388 |
| Acquisition costs | 148 |
| Total purchase price | 9,536 |

**Rival Energy Ltd.**

On January 23, 2008, a subsidiary of the Trust acquired all of the outstanding shares of Rival Energy Ltd. ("Rival"), a public oil and gas company, for consideration of $30.06 million. Consideration consisted of $16.40 million cash, the issuance of 573,300 Zargon trust units valued at $23.32 per unit and acquisition costs of $0.29 million.

The results of operations for Rival have been included in the consolidated financial statements since January 23, 2008.

The acquisition was accounted for by the purchase method and the purchase price allocation is as follows:

**Net Assets Acquired**

| ($ thousands) | |
|---|---|
| Property and equipment | 54,065 |
| Goodwill | 2,969 |
| Working capital deficiency | (854) |
| Long term debt | (16,914) |
| Future income tax liability | (5,443) |
| Asset retirement obligations | (3,767) |
| Total net assets acquired | 30,056 |

**Consideration**

| ($ thousands) | |
|---|---|
| Cash | 16,400 |
| Trust units issued | 13,369 |
| Acquisition costs | 287 |
| Total purchase price | 30,056 |

## 5. PROPERTY AND EQUIPMENT

| ($ thousands) | Cost | December 31, 2009 Accumulated Depletion and Depreciation | Net Book Value |
|---|---|---|---|
| Petroleum, natural gas properties and other equipment [1] | **771,121** | **347,260** | **423,861** |
| Leasehold improvements and office equipment | **4,136** | **2,033** | **2,103** |
| | **775,257** | **349,293** | **425,964** |

| ($ thousands) | Cost | December 31, 2008 Accumulated Depletion and Depreciation | Net Book Value |
|---|---|---|---|
| Petroleum, natural gas properties and other equipment [1] | 667,944 | 282,949 | 384,995 |
| Leasehold improvements and office equipment | 3,380 | 1,629 | 1,751 |
| | 671,324 | 284,578 | 386,746 |

*(1) As a result of shareholders redeeming exchangeable shares, property and equipment has cumulatively increased $56.13 million, $0.97 million relating to 2009, $3.39 million relating to 2008 and $51.76 million relating to prior years. The effect of these increases has resulted in additional depletion and depreciation expense of approximately $27.22 million, $4.91 million relating to 2009, $5.59 million relating to 2008 and $16.72 million relating to prior years.*

At December 31, 2009, petroleum, natural gas properties and equipment include $24.37 million (2008 – $24.73 million) relating to undeveloped properties that have been excluded from the depletion calculation.

An impairment test calculation was performed on the Trust's petroleum, natural gas properties and equipment at December 31, 2009 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Trust's petroleum, natural gas properties and equipment; consequently an impairment provision was not recorded. This impairment calculation was performed separately on both the Canadian and US cost centres.

The following table outlines benchmark prices used in the impairment test at December 31, 2009:

| Year | WTI Crude Oil ($US/bbl) | Exchange Rate ($US/$Cdn) | WTI Crude Oil ($Cdn/bbl) | AECO Gas ($Cdn/gj) |
|---|---|---|---|---|
| 2010 | **81.92** | **0.95** | **86.23** | **5.38** |
| 2011 | **85.85** | **0.95** | **90.37** | **5.87** |
| 2012 | **87.84** | **0.95** | **92.46** | **6.04** |
| 2013 | **89.21** | **0.95** | **93.91** | **6.18** |
| 2014 | **90.74** | **0.95** | **95.52** | **6.33** |
| Thereafter (inflation %) | **2.0%** | **0.95** | **2.0%** | **2.0%** |

Actual prices used in the impairment test were adjusted for commodity price differentials specific to Zargon.

## 6. LONG TERM DEBT

On July 27, 2009, Zargon amended and renewed its syndicated committed credit facilities, the result of which was the maintaining of the available facilities and borrowing base of $180 million. These facilities consist of a $170 million tranche available to the Canadian borrower and a US $8 million tranche available to the US borrower. A $300 million demand debenture on the assets of the subsidiaries of the Trust has been provided as security for these facilities. The facilities are fully revolving for a 336 day period with the provision for an annual extension at the option of the lenders and upon notice from Zargon's management. The next renewal date is June 29, 2010. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 336 day period. Repayment would not be required until the end of the non-revolving term, and, as such, these facilities have been classified as long term debt.

Interest rates fluctuate under the syndicated facilities with Canadian prime, US prime and US base rates plus an applicable margin between 125 basis points and 275 basis points (2008 – zero and 32.5 basis points, respectively), as well as with Canadian banker's acceptance and LIBOR rates plus an applicable margin between 275 basis points and 425 basis points (2008 – 97.5 and 157.5 basis points, respectively). At December 31, 2009, $76.58 million (December 31, 2008 - $77.58 million) had been drawn on the syndicated

committed credit facilities with any unused amounts subject to standby fees. In the normal course of operations Zargon enters into various letters of credit. At December 31, 2009, the approximate value of outstanding letters of credit totalled $0.61 million (December 31, 2008 - $0.52 million). The letters of credit reduce the amount of Zargon's available credit facilities to $102.81 million at December 31, 2009 (2008 - $101.90 million).

Zargon reviews its compliance with its bank debt covenants on a quarterly basis and has no violations as at December 31, 2009. Zargon's management is planning to convert to a corporation from its current trust structure towards the end of 2010. In order for this conversion to occur, Zargon would have to ensure that all legal and regulatory requirements are satisfied and would be required to obtain the consent of the lenders under Zargon's current syndicated credit facility.

## 7. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by management based on Zargon's net working interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. Zargon has estimated the net present value of its total asset retirement obligations to be $35.47 million as at December 31, 2009 (2008 – $28.59 million), based on a total future liability of $164.58 million (2008 – $142.52 million). These payments are expected to be made over the next 40 years with the majority of the costs being incurred after 2019. Commencing July 1, 2005, incremental asset retirement obligations are calculated using a revised credit adjusted risk-free rate of 7.5 percent. Asset retirement obligations prior to this period were calculated using a credit adjusted risk-free rate of 8.5 percent. An inflation rate of two percent used in the calculation of the present value of the asset retirement obligation remains unchanged.

The following table reconciles Zargon's asset retirement obligations:

| | Year Ended December 31, | |
|---|---|---|
| ($ thousands) | **2009** | 2008 |
| Balance, beginning of year | **28,592** | 21,184 |
| Net liabilities incurred/acquired | **7,353** | 5,920 |
| Liabilities settled | **(3,056)** | (897) |
| Accretion expense | **2,744** | 2,183 |
| Foreign exchange | **(165)** | 202 |
| Balance, end of year | **35,468** | 28,592 |

## 8. UNITHOLDERS' EQUITY

Pursuant to the Plan of Arrangement on July 15, 2004, 14.87 million units of the Trust and 3.66 million exchangeable shares (see note 9) of the Company were issued in exchange for all of the outstanding shares of the Company on a one-for-one basis.

The Trust is authorized to issue an unlimited number of voting trust units.

### Trust Units

| | December 31, 2009 | | December 31, 2008 | |
|---|---|---|---|---|
| (thousands) | **Number of Units** | **Amount ($)** | Number of Units | Amount ($) |
| Balance, beginning of year | **18,479** | **120,650** | 17,076 | 89,688 |
| Unit rights exercised for cash | **98** | **1,295** | 69 | 1,166 |
| Unit-based compensation recognized on exercise of unit rights | **–** | **391** | – | 246 |
| Issued on corporate and property acquisitions [note 4] | **2,030** | **30,397** | 1,045 | 23,910 |
| Equity issuance | **2,365** | **35,475** | – | – |
| Issue costs, net of future tax effect of $487 | **–** | **(1,544)** | – | – |
| Issued on conversion of exchangeable shares | **125** | **2,176** | 289 | 5,640 |
| Balance, end of year | **23,097** | **188,840** | 18,479 | 120,650 |

On June 5, 2009, the Trust closed an offering of 2.365 million trust units on a bought deal basis at $15.00 per unit for total gross proceeds of $35.48 million ($33.44 million net of issue costs).

**Trust Unit Rights Incentive Plan**

The Trust has a unit rights incentive plan (the "Old Plan") that allows the Trust to issue rights to acquire trust units to directors, officers, employees and other service providers. On April 22, 2009, a new unit rights incentive plan (the "New Plan") was approved by the unitholders. The Trust is authorized to issue up to an aggregate of 2.13 million unit rights; however, the number of trust units reserved for issuance upon exercise of the rights shall not at any time exceed 10 percent of the aggregate number of the total outstanding units, including units issuable upon exchange of exchangeable shares of Zargon and other fully paid securities of Zargon entities exchangeable into units, which are the economic equivalent of units including full voting rights. At the time of grant, unit right exercise prices approximate the market price for the trust units. At the time of exercise, the rights holder has the option of exercising at the original grant price or the exercise price as calculated under the Old Plan or the New Plan (the "modified price"). Under the Old Plan, the modified price was based on the increment of the amount the monthly distribution exceeded a monthly return of 0.833 percent of the Trust's recorded net book value of oil and natural gas properties (as defined in the Old Plan). Under the New Plan, if the monthly distribution exceeds the monthly return of 0.833 percent of the Trust's recorded net book value of oil and natural gas properties (as defined in the New Plan), the entire amount (not the increment) of the distribution is deducted from the original grant price. Rights granted under either Plan generally vest over a three-year period and expire approximately five years from the grant date. Zargon uses a fair value methodology to value the unit rights grants.

The following table summarizes information about the Trust's unit rights under the Old Plan:

| | **December 31, 2009** | | December 31, 2008 | |
|---|---|---|---|---|
| | **Number of Unit Rights (thousands)** | **Weighted Average Exercise Price Initial and Modified ($/unit right)** | Number of Unit Rights (thousands) | Weighted Average Exercise Price Initial and Modified ($/unit right) |
| Outstanding at beginning of year | **1,654** | **25.57 / 23.63** | 1,488 | 26.41 / 24.60 |
| Unit rights granted | **–** | **–** | 445 | 22.65 |
| Unit rights exercised | **(98)** | **13.21** | (69) | 16.92 |
| Unit rights cancelled | **(234)** | **26.60** | (210) | 27.22 |
| Outstanding at end of year | **1,322** | **25.97 / 23.52** | 1,654 | 25.57 / 23.63 |
| Unit rights exercisable at year end | **961** | **26.87 / 23.99** | 839 | 26.51 / 23.57 |

The following table summarizes information about the Trust's unit rights under the New Plan:

| | **December 31, 2009** | | December 31, 2008 | |
|---|---|---|---|---|
| | **Number of Unit Rights (thousands)** | **Weighted Average Exercise Price Initial and Modified ($/unit right)** | Number of Unit Rights (thousands) | Weighted Average Exercise Price Initial and Modified ($/unit right) |
| Outstanding at beginning of year | **–** | **– / –** | – | – / – |
| Unit rights granted | **434** | **15.81** | – | – |
| Unit rights exercised | **–** | **–** | – | – |
| Unit rights cancelled | **(13)** | **15.76** | – | – |
| Outstanding at end of year | **421** | **15.81 / 14.58** | – | – / – |
| Unit rights exercisable at year end | **–** | **– / –** | – | – / – |

The following tables summarize information about unit rights outstanding and exercisable at December 31, 2009:

For the Old Plan at the initial grant price:

| | Unit Rights Outstanding | | | Unit Rights Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices ($/unit right) | Number Outstanding (thousands) | Weighted Average Remaining Contractual Life | Weighted Average Exercise Price ($/unit right) | Number Exercisable (thousands) | Weighted Average Exercise Price ($/unit right) |
| 13.00 – 25.06 | 613 | 2.1 years | 22.58 | 383 | 22.99 |
| 26.00 – 27.40 | 310 | 1.8 years | 26.65 | 204 | 26.88 |
| 27.91 – 29.93 | 146 | 1.6 years | 28.81 | 121 | 28.99 |
| 31.09 – 33.05 | 253 | 0.7 years | 31.72 | 253 | 31.72 |
| | 1,322 | | 25.97 | 961 | 26.87 |

For the Old Plan at the modified price:

| | Unit Rights Outstanding | | | Unit Rights Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices ($/unit right) | Number Outstanding (thousands) | Weighted Average Remaining Contractual Life | Weighted Average Exercise Price ($/unit right) | Number Exercisable (thousands) | Weighted Average Exercise Price ($/unit right) |
| 12.20 – 22.37 | 613 | 2.1 years | 20.53 | 383 | 20.48 |
| 22.91 – 25.04 | 310 | 1.8 years | 24.26 | 204 | 23.94 |
| 25.89 – 26.42 | 146 | 1.6 years | 26.13 | 121 | 26.17 |
| 26.95 – 30.23 | 253 | 0.7 years | 28.31 | 253 | 28.31 |
| | 1,322 | | 23.52 | 961 | 23.99 |

For the New Plan at the initial grant price:

| | Unit Rights Outstanding | | | Unit Rights Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices ($/unit right) | Number Outstanding (thousands) | Weighted Average Remaining Contractual Life | Weighted Average Exercise Price ($/unit right) | Number Exercisable (thousands) | Weighted Average Exercise Price ($/unit right) |
| 15.56 | 368 | 4.1 years | 15.56 | – | – |
| 15.80 – 17.31 | 21 | 4.1 years | 16.73 | – | – |
| 18.00 – 18.05 | 29 | 4.1 years | 18.03 | – | – |
| 18.67 | 3 | 4.1 years | 18.67 | – | – |
| | 421 | | 15.81 | – | – |

For the New Plan at the modified price:

| | Unit Rights Outstanding | | | Unit Rights Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices ($/unit right) | Number Outstanding (thousands) | Weighted Average Remaining Contractual Life | Weighted Average Exercise Price ($/unit right) | Number Exercisable (thousands) | Weighted Average Exercise Price ($/unit right) |
| 14.24 | 368 | 4.1 years | 14.24 | – | – |
| 14.75 – 16.63 | 21 | 4.1 years | 15.91 | – | – |
| 17.51 – 17.73 | 29 | 4.1 years | 17.59 | – | – |
| 18.49 | 3 | 4.1 years | 18.49 | – | – |
| | 421 | | 14.58 | – | – |

### Unit-Based Compensation

The weighted average assumptions used for unit rights granted in 2009 include a volatility factor of expected market price of 34.5 percent, a risk-free interest rate of 1.7 percent and an expected life of the unit rights of four years. The fair value of the unit rights granted under the New Plan in the year was calculated at $4.50 per unit right. These unit rights, together with the continued vesting of unit rights granted in prior years, resulted in unit-based compensation expense in 2009 of $1.26 million (2008 – $1.19 million).

Compensation expense associated with unit rights granted under either Plan is recognized in earnings over the vesting period of the Plan with a corresponding increase in contributed surplus. The exercise of trust unit rights is recorded as an increase in trust units with a corresponding reduction in contributed surplus. Forfeiture of rights are recorded as a reduction in expenses in the period in which they occur if the rights have not yet vested.

The following table summarizes information about the Trust's contributed surplus account:

**Contributed Surplus**

($ thousands)

| | |
|---|---|
| **Balance, December 31, 2007** | 3,714 |
| Unit-based compensation expense [1] | 1,149 |
| Unit-based compensation recognized on exercise of unit rights | (246) |
| **Balance, December 31, 2008** | **4,617** |
| Unit-based compensation expense [1] | **1,245** |
| Unit-based compensation recognized on exercise of unit rights | **(391)** |
| **Balance, December 31, 2009** | **5,471** |

*(1) During the fourth quarter of 2008, the Trust issued 10,000 unit appreciation rights ("UARs") with an intrinsic value of $0.02 million at December 31, 2009 ($0.04 million at December 31, 2008). These UARs are awards entitling the recipients to receive cash in an amount equivalent to any excess of the market value of a stated number of units over a stated price. UARs are included in unit-based compensation expense; however rewards settled in cash are liabilities and therefore are not included in contributed surplus.*

### Trust Unit Redemption

Under the terms of the Trust Indenture, unitholders may require the Trust to redeem all or any part of the trust units at a price and under certain terms and conditions as specified in the Trust Indenture. The redemption price per trust unit will be equal to the lesser of: (i) 90 percent of the "market price" of the trust units on the principal market on which the trust units are quoted for trading during the 10 trading day period commencing immediately after the date on which the trust units are tendered to Zargon for redemption; and (ii) the closing market price on the principal market on which the trust units are quoted for trading on the date that the trust units are so tendered for redemption. Trust units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the Trust's option: (i) a cash payment; or (ii) a distribution of notes and/or redemption notes. It is anticipated that this redemption right will not be the primary mechanism for holders of trust units to dispose of their trust units. Notes or redemption notes which may be distributed in specie to unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop for such notes or redemption notes. Notes or redemption notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans. To date, no trust units have been tendered for redemption.

## 9. NON-CONTROLLING INTEREST – EXCHANGEABLE SHARES

Zargon Oil & Gas Ltd. is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares are convertible into trust units at the option of the shareholder, based on the exchange ratio, which is adjusted monthly to reflect the distribution paid on the trust units. Cash distributions are not paid on the exchangeable shares. During the year, a total of 0.08 million (2008 – 0.21 million) exchangeable shares were converted into 0.12 million (2008 – 0.29 million) trust units based on the exchange ratio at the time of conversion. At December 31, 2009, the exchange ratio was 1.63709 (2008 – 1.43643) trust units per exchangeable share. As set out in the Arrangement, the exchangeable shares are entitled to vote equally to the number of trust units for which each exchangeable share is convertible into a trust unit on the record date. The Board of Directors of Zargon Oil & Gas Ltd. hold the option to redeem all outstanding exchangeable shares for trust units on or before July 15, 2014. At such time, should the Board of Directors not extend the term of the exchangeable shares, there would be no remaining non-controlling interest.

Pursuant to EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts", if certain conditions are met, the exchangeable shares issued by a subsidiary must be reflected as non-controlling interest on the consolidated balance sheets and, in turn, net earnings must be reduced by the amount of net earnings attributed to the non-controlling interest.

The non-controlling interest on the consolidated balance sheets consists of the book value of exchangeable shares at the time of the Plan of Arrangement, plus net earnings attributable to the exchangeable shareholders, less exchangeable shares (and related cumulative earnings) redeemed. The net earnings attributable to the non-controlling interest on the consolidated statements of earnings and comprehensive income and accumulated earnings represents the cumulative share of net earnings attributable to the non-controlling interest based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable each year end.

**Non-Controlling Interest – Exchangeable Shares**

| | December 31, 2009 | | December 31, 2008 | |
|---|---|---|---|---|
| (thousands, except exchange ratio) | Number of Shares | Amount ($) | Number of Shares | Amount ($) |
| **Balance, beginning of year** | **1,862** | **27,610** | 2,071 | 20,730 |
| Exchanged for trust units at book value and including earnings attributed during the period | **(78)** | **(1,470)** | (209) | (3,220) |
| Earnings attributable to non-controlling interest | **–** | **337** | – | 10,100 |
| **Balance, end of year** | **1,784** | **26,477** | 1,862 | 27,610 |
| Exchange ratio, end of period | **1.63709** | | 1.43643 | |
| Trust units issuable upon conversion of exchangeable shares, end of year | **2,920** | | 2,675 | |

The proforma total units outstanding at December 31, 2009, including trust units outstanding, and trust units issuable upon conversion of exchangeable shares and after giving rise to the exchange ratio at the end of the year, is 26.02 million units (2008 – 21.15 million units).

The effect of EIC-151 on Zargon's unitholders' capital and exchangeable shares is as follows:

| ($ thousands) | Zargon Energy Trust Units | Zargon Oil & Gas Ltd. Exchangeable Shares | Total |
|---|---|---|---|
| **Balance at December 31, 2007** | 89,688 | 20,730 | 110,418 |
| Issued on redemption of exchangeable shares at book value | 508 | (508) | – |
| Effect of EIC-151 | 5,132 | 7,388 | 12,520 |
| Unit-based compensation recognized on exercise of unit rights | 246 | – | 246 |
| Issued on corporate and property acquisitions | 23,910 | – | 23,910 |
| Unit rights exercised for cash | 1,166 | – | 1,166 |
| **Balance at December 31, 2008** | **120,650** | **27,610** | **148,260** |
| Issued on redemption of exchangeable shares at book value | **192** | **(192)** | **–** |
| Effect of EIC-151 | **1,984** | **(941)** | **1,043** |
| Unit-based compensation recognized on exercise of unit rights | **391** | **–** | **391** |
| Issued on corporate and property acquisitions | **30,397** | **–** | **30,397** |
| Unit rights exercised for cash | **1,295** | **–** | **1,295** |
| Equity issuance (net of share issue costs and future taxes) | **33,931** | **–** | **33,931** |
| **Balance at December 31, 2009** | **188,840** | **26,477** | **215,317** |

EIC-151 states that exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either a non-controlling interest or debt on the consolidated balance sheets unless they meet certain criteria. The exchangeable shares issued by Zargon Oil

& Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as a non-controlling interest.

As a result of EIC-151, the Trust has increased its unitholders' equity and non-controlling interest for 2009 by $1.04 million (2008 – $12.52 million) on the Trust's consolidated balance sheets. Consolidated net earnings for 2009 have been reduced for net earnings attributable to the non-controlling interest by $0.34 million (2008 – $10.10 million). In accordance with EIC-151 and given the circumstances in Zargon's case, each redemption is accounted for as a step-purchase, which for 2009 additionally resulted in an increase in property and equipment of $0.97 million (2008 – $3.39 million), and an increase in future income tax liability of $0.27 million (2008 – $0.97 million). Funds flow from operating activities were not impacted by this change.

The cumulative impact to date of the application of EIC-151 has been to increase gross property and equipment by $56.13 million (for depletion impact see note 5), unitholders' equity and non-controlling interest by $66.91 million, future income tax liability by $18.46 million and an allocation of net earnings to exchangeable shareholders of $29.24 million.

## 10. WEIGHTED AVERAGE NUMBER OF TOTAL UNITS

| (thousands of units) | **2009** | 2008 |
|---|---|---|
| Basic | **21,099** | 18,021 |
| Diluted | **23,745** | 20,632 |

Dilution amounts of 2.65 million units (2008 – 2.61 million) were added to the weighted average number of units outstanding during the year in the calculation of diluted per unit amounts. These unit additions represent the dilutive effect of unit rights according to the treasury stock method and also include exchangeable shares using the "if-converted" method. Due to the fact that at the time of exercise, the rights holder has the option of exercising at the original grant price or a modified price as calculated under the Old Plan and the New Plan, the prices used in the treasury stock calculation are the lower prices calculated under the Old Plan and the New Plan. An adjustment to the numerator amount was required in the diluted calculation to provide for the earnings of $0.34 million (2008 – $10.10 million) attributable to the non-controlling interest pertaining to the exchangeable shareholders.

## 11. CAPITAL DISCLOSURES

The Trust's capital structure is comprised of unitholders' equity plus long term debt. The Trust's objectives when managing its capital structure are to:

i) maintain financial flexibility so as to preserve Zargon's access to capital markets and its ability to meet its financial obligations; and

ii) finance internally generated growth as well as acquisitions.

The Trust monitors its capital structure and short term financing requirements using the non-GAAP financial metric of debt net of working capital ("net debt") to funds flow from operating activities. Net debt, as used by the Trust, is calculated as bank debt and any working capital deficit excluding the current portion of unrealized risk management assets and liabilities and future income taxes. Funds flow from operating activities represent net earnings/losses and asset retirement expenditures except for non-cash items. The metric is used to steward the Trust's overall debt position as a measure of the Trust's overall financial strength and is calculated as follows:

| ($ thousands, except ratio) | **December 31, 2009** | December 31, 2008 |
|---|---|---|
| Net debt | **88,008** | 87,707 |
| Funds flow from operating activities | **86,352** | 106,909 |
| Net debt to funds flow from operating activities ratio | **1.02** | 0.82 |

As at December 31, 2009, Zargon's net debt to funds flow from operating activities ratio was 1.02, an increase from 0.82 at December 31, 2008, primarily due to weak commodity prices negatively affecting funds flow from operating activities. Bank debt levels increased throughout the year when the Trust acquired Masters on April 29, 2009 and Churchill on September 23, 2009. On June 5, 2009, the Trust closed an offering of 2.365 million trust units on a bought deal basis of $15.00 per unit for total gross proceeds of $35.48 million ($33.44 million net of issue costs). On July 27, 2009, Zargon amended and renewed its syndicated

committed credit facilities of $180 million. The next renewal date is June 29, 2010. These facilities continue to be available for general corporate purposes and the potential acquisition of oil and natural gas properties.

To manage its capital structure, the Trust may adjust capital spending, adjust distributions paid to unitholders, issue new units, issue new debt or repay existing debt.

The Trust's capital management objectives, evaluation measures, definitions and targets have remained unchanged over the periods presented. Zargon is subject to certain financial covenants in its credit facility agreements and is in compliance with all financial covenants.

Zargon reviews its compliance with its bank debt covenants on a quarterly basis and has no violations as at December 31, 2009. Zargon's management is planning to convert to a corporation from its current trust structure towards the end of 2010. In order for this conversion to occur, Zargon would have to ensure that all legal and regulatory requirements are satisfied and would be required to obtain the consent of the lenders under Zargon's current syndicated credit facility.

## 12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT CONTRACTS

### Fair Value of Financial Assets and Liabilities

Zargon's financial assets and liabilities are comprised of accounts receivable, deposits, accounts payable, cash distributions payable, unrealized risk management assets and liabilities and long term debt. Fair values of financial assets and liabilities, summarized information related to risk management positions and discussion of risks associated with financial assets and liabilities are presented as follows:

A) Fair Value of Financial Assets and Liabilities

Accounts receivable are designated as "loans and receivables". Accounts payable and accrued liabilities, cash distributions payable and long term debt are designated as "other liabilities". The fair values of these accounts approximate their carrying amounts.

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading". These accounts are recorded at their estimated fair value using quoted market prices.

Financial instruments of the Trust carried on the consolidated balance sheets are carried at amortized cost with the exception of risk management contracts, which are carried at fair value.

All of the Trust's risk management contracts are transacted in active markets. The Trust classifies the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- Level I

Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

- Level II

Pricing inputs are other than quoted prices in active markets included in Level I. Prices in Level II are either directly or indirectly observable as of the reporting date. Level II valuations are based on inputs, included quoted forward prices for commodities, time value and volatility factors, which are can be substantially observed or corroborated in the marketplace.

- Level III

Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The Trust's risk management contracts have been assessed on the fair value hierarchy described above. The Trust's risk management contracts are classified as Level II. Assessment of the significance of a particular input into the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level.

B) Risk Management Assets and Liabilities

The Trust is a party to certain financial instruments that have fixed the price of a portion of its oil and natural gas production and foreign exchange conversion rates. The Trust enters into these contracts for risk management purposes only, in order to protect a portion of its future cash flow from the volatility of oil and natural gas commodity prices and foreign exchange rates. For financial

risk management contracts, the Trust considers these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and, accordingly, any unrealized gains or losses are recorded in earnings based on the fair value (mark-to-market) of the contracts at each reporting period. The unrealized loss on the statement of earnings and comprehensive income and accumulated earnings for 2009 was $36.39 million and the unrealized gain for 2008 was $44.38 million.

As at December 31, 2009, the Trust had the following outstanding commodity, electricity and foreign exchange risk management contracts:

**Commodity Financial Risk Management Contracts:**

| | Rate | Weighted Average Price | Range of Terms | Fair Market Value Asset/(Liability) ($ thousands) |
|---|---|---|---|---|
| Oil swaps | 300 bbl/d | $132.98 US/bbl | Jan. 1/10 – Jun. 30/10 | 2,956 |
| | 1,400 bbl/d | $73.11 US/bbl | Jan. 1/10 – Dec. 31/10 | (4,551) |
| | 400 bbl/d | $77.40 US/bbl | Jan. 1/10 – Jun. 30/11 | (1,382) |
| | 300 bbl/d | $83.30 US/bbl | Jul. 1/10 – Dec. 31/10 | (19) |
| | 300 bbl/d | $77.25 US/bbl | Jan. 1/11 – Sep. 30/11 | (749) |
| **Total Fair Market Value, Commodity Price Financial Contracts** | | | | **(3,745)** |

Oil swaps are settled against the NYMEX WTI pricing index.

**Foreign Exchange Financial Risk Management Contracts:**

| | Average Monthly US Dollar Volume ($ thousands) | Foreign Exchange Rate ($Cdn/$US) | Range of Terms | Fair Market Value Asset ($ thousands) |
|---|---|---|---|---|
| Foreign exchange swaps | 1,203 | 1.1715 | Jan. 1/10 – Jun. 30/10 | 865 |
| **Total Fair Market Value, Foreign Exchange Financial Contracts** | | | | **865** |

The contracts are settled based on the average daily noon close rate for US dollars converted to Canadian dollars as published by the Bank of Canada.

**Electricity Financial Risk Management Contracts:**

| | Rate | Weighted Average Price | Range of Terms | Fair Market Value Liability ($ thousands) |
|---|---|---|---|---|
| Electricity swaps | 6 MWs/d | $80.42/MWh | Jan. 1/10 – Dec. 31/10 | (70) |
| | 6 MWs/d | $79.33/MWh | Jan. 1/11 – Dec. 31/11 | (63) |
| **Total Fair Market Value, Electricity Financial Contracts** | | | | **(133)** |

Electricity swaps are settled against the AESO pricing index.

**Physical Risk Management Contracts:**

| | Rate | Weighted Average Price | Range of Terms | Fair Market Value Loss ($ thousands) |
|---|---|---|---|---|
| Electricity swaps | 32 MWs/d | $55.50/MWh | Jan. 1/10 – Mar. 31/11 | (82) |
| **Total Fair Market Value, Physical Contracts** | | | | **(82)** |

Commodity price contracts are settled by way of physical delivery and are recognized as part of the normal revenue stream. Electricity contracts are settled by way of physical delivery and are recognized as part of the normal operating cost stream. These instruments have no book values recorded in the consolidated financial statements.

**Commodity Price Sensitivities**

The following table summarizes the sensitivity of the fair value of the Trust's risk management positions to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, the Trust believes 10 percent volatility is a reasonable long term measure.

Fluctuations of 10 percent in commodity prices could have resulted in unrealized gains or losses on risk management contracts impacting net earnings as follows:

| ($ thousands) | December 31, 2009 | December 31, 2008 |
|---|---|---|
| Natural gas price | – | 474 |
| Crude oil price | 8,617 | 3,584 |

C) Risks Associated with Financial Assets and Liabilities

The Trust is exposed to financial risks arising from its financial assets and liabilities. The financial risks include market risk (commodity prices, interest rates and foreign exchange rates), credit risk and liquidity risk.

• Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices and is comprised of the following:

- Commodity Price Risk

As a means of mitigating exposure to commodity price risk volatility, the Trust has entered into various derivative agreements. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Trust's policy is to not use derivative financial instruments for speculative purposes.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Trust enters into swaps, which fix the Canadian dollar AECO prices.

Crude Oil – The Trust has partially mitigated its exposure to the WTI NYMEX price with fixed price swaps.

- Interest Rate Risk

Borrowings under bank credit facilities are market rate based (variable interest rates); thus, carrying values approximate fair values.

At the December 31, 2009 debt pricing levels, the increase or decrease in net earnings for each one percent change in interest rates would amount to $0.82 million (2008 - $0.83 million).

- Foreign Exchange Risk

As Zargon operates in North America, fluctuations in the exchange rate between the US/Canadian dollar can have a significant effect on the Trust's reported results. A $0.01 change in the US to Canadian dollar exchange rate would have resulted in a $0.61 million (2008 - $1.16 million) increase or decrease in net earnings for the year ended December 31, 2009. In order to mitigate the Trust's exposure to foreign exchange fluctuations, the Trust enters into foreign exchange derivative agreements.

• Credit Risk

Credit risk is the risk that the counterparty to a financial asset will default, resulting in the Trust incurring a financial loss. This credit exposure is mitigated with credit practices that limit transactions according to counterparties' credit quality. A substantial portion of the Trust's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks.

The maximum credit risk exposure associated with accounts receivable, accrued revenues and risk management assets is the total carrying value. The Trust monitors these balances monthly to limit the risk associated with collection. Of Zargon's accounts receivable at December 31, 2009, approximately 40 percent (December 31, 2008 – 37 percent) was owing from two companies and Zargon anticipates full collection.

The Trust's allowance for doubtful accounts was $0.10 million as at December 31, 2009 and $0.10 million as at December 31, 2008. During 2009, the Trust did not record any additional provisions for non-collectible accounts receivable.

When determining whether amounts that are past due are collectible, management assesses the credit worthiness and past payment history of the counterparty, as well as the nature of the past due amount. Zargon considers all material amounts greater than 90 days to be past due. As at December 31, 2009, $0.78 million of accounts receivable are past due, excluding amounts described above, all of which are considered to be collectable.

- Liquidity Risk

Liquidity risk is the risk the Trust will encounter difficulties in meeting its financial liability obligations. The Trust manages its liquidity risk through cash and debt management. See note 11 for a more detailed discussion.

As at December 31, 2009, Zargon had available unused committed bank credit facilities of approximately $102.81 million compared to $101.90 million at December 31, 2008. The Trust believes it has sufficient funding through the use of these facilities to meet foreseeable borrowing requirements.

The timing of cash outflows relating to financial liabilities are outlined in the table below:

| ($ thousands) | 1 year | 2–3 years | Total |
|---|---|---|---|
| Accounts payable and accrued liabilities | 34,507 | – | 34,507 |
| Cash distributions payable | 4,157 | – | 4,157 |
| Risk management liabilities [1] | 6,032 | 1,270 | 7,302 |
| Long term debt [2] | – | 76,580 | 76,580 |

*(1) See the section titled "Commodity Price Sensitivities" in this note for a better understanding of the volatility around these amounts.*

*(2) See note 6 for the details on the credit facilities.*

## 13. INCOME TAXES

The Trust is a taxable entity under the Income Tax Act (Canada) and, until 2011, is taxable only on income that is not distributed or distributable to the unitholders. As the Trust allocates all of its Canadian taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no current tax provision for Canadian income tax expense has been incurred by the Trust. Withholding taxes, provincial capital taxes and US income taxes are provided for under current income tax expense.

In the Trust's structure, payments are made between the Company and the Trust that result in the transferring of taxable income from the Company to individual unitholders. These payments may reduce future income tax liabilities previously recorded by the Company that would be recognized as a recovery of income tax in the period incurred.

On October 31, 2006, the Federal Government announced tax proposals pertaining to taxation of distributions paid by trusts and the personal tax treatment of trust distributions. Currently, the Trust does not pay tax on distributions as tax is paid by the unitholders. On June 12, 2007, the Federal Government enacted these tax proposals, which would have resulted in taxation of distributions at the Trust level at a rate of 31.5 percent effective January 1, 2011. Subsequent 2007 fourth quarter legislation lowered this tax rate to 29.5 percent in 2011 and 28.0 percent beyond 2011.

On February 26, 2008, the Federal Government, in its Federal Budget, announced further changes to the specified investment flow through ("SIFT") tax rules. The provincial component of the SIFT tax will be based on the provincial rates where the SIFT has a permanent establishment rather than using a 13.0 percent flat rate. During the 2009 first quarter this tax rate change had been substantively enacted, and the future income tax impact has been recorded in the consolidated financial statements. Under the legislation, the Trust now estimates the effective tax rate on the post 2010 reversal of these temporary differences to be approximately 26.5 percent for 2011 and 25.0 percent thereafter. Until 2011, Zargon's future tax obligations are reduced as distributions are made from the Trust and, consequently, it is anticipated that Zargon's effective tax rate will continue to be low until that time.

The amount and timing of reversals of temporary differences will also depend on the Trust's future operating results, acquisitions and dispositions of assets and liabilities, and distributions. A significant change in any of the preceding assumptions could materially affect management's estimate of the future tax liability.

On December 15, 2006, the Canadian Federal Department of Finance stated its intention to allow conversions of SIFT income trusts to a corporation without any adverse tax consequences to investors. On July 14, 2008, the Department of Finance released the

draft legislative proposals to allow the conversion of these SIFT trusts into corporations. Zargon is currently reviewing and assessing this recent legislation and is considering its potential impact on the organization while Zargon's management develops its strategic plan beyond December 2010, which is the effective date of the new SIFT tax rules.

Income taxes differ from the amounts which would be obtained by applying the statutory income tax rates to earnings before income taxes as follows:

| ($ thousands) | 2009 | 2008 |
|---|---|---|
| Statutory income tax rates | **29.42%** | 30.08% |
| Expected income taxes expense (recovery) | **(3,942)** | 28,632 |
| Add (deduct) income tax effect of: | | |
| Rate adjustments | **458** | (1,225) |
| Cash distributions | **(13,523)** | (11,757) |
| Capital taxes and withholding taxes | **285** | 969 |
| Other | **267** | 183 |
| | **(16,455)** | 16,802 |

The 2009 and 2008 years include recoveries relating to reductions in future federal and provincial income tax rates substantively enacted during the respective years.

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

The components of Zargon's net future income tax liability are as follows:

| ($ thousands) | 2009 | 2008 |
|---|---|---|
| Net book value of property and equipment in excess of tax pools | **46,983** | 49,829 |
| Deferred partnership earnings | **7,560** | 7,494 |
| Asset retirement obligations | **(9,199)** | (7,525) |
| Current unrealized risk management (asset)/liability | **(495)** | 8,553 |
| Long-term unrealized risk management (asset)/liability | **(361)** | 1,321 |
| Non-capital losses | **(14,296)** | (1,046) |
| Share issue costs | **(491)** | (31) |
| Other | **(230)** | (338) |
| | **29,471** | 58,257 |

As at December 31, 2009, Zargon's estimated tax pools are as follows:

| ($ thousands) | December 31, 2009 | December 31, 2008 |
|---|---|---|
| Canadian oil and gas property expenses in the Trust | **30,610** | 33,992 |
| Canadian oil and gas property expenses in other entities | **43,629** | 29,846 |
| Canadian development expenses | **47,713** | 36,224 |
| Canadian exploration expenses | **49,411** | 39,332 |
| Capital cost allowance | **61,290** | 51,218 |
| Non-capital losses | **60,600** | 752 |
| US tax pools | **2,425** | 3,185 |
| Partnership deferral | **(6,290)** | (8,312) |
| Other | **3,750** | 1,722 |
| | **293,138** | 187,959 |

## 14. COMMITMENTS

The Trust is committed to future minimum payments for natural gas transportation sales commitments in addition to operating leases for office space, office equipment and vehicles. Payments required under these commitments for each of the next five years are: 2010 – $2.95 million; 2011 – $1.36 million; 2012 – $0.76 million; 2013 – $nil; 2014 – $nil; thereafter – $nil.

## 15. CONTINGENCIES AND GUARANTEES

In the normal course of operations, Zargon executes agreements that provide for indemnification and guarantees to counterparties in transactions such as the sale of assets and operating leases.

These indemnifications and guarantees may require compensation to counterparties for costs and losses incurred as a result of various events, including breaches of representations and warranties, loss of or damages to property, environmental liabilities or as a result of litigation that may be suffered by counterparties.

Certain indemnifications can extend for an unlimited period and generally do not provide for any limit on the maximum potential amount. The nature of substantially all of the indemnifications prevents the Trust from making a reasonable estimate of the maximum potential amount that might be required to pay counterparties as the agreements do not specify a maximum amount, and the amounts depend on the outcome of future contingent events, the nature and likelihood of which cannot be determined at this time.

The Trust indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their services to the Trust to the extent permitted by law. The Trust has acquired and maintains liability insurance for its directors and officers. The Trust is party to various legal claims associated with the ordinary conduct of business. The Trust does not anticipate that these claims will have a material impact on its financial position.

## 16. CHANGES IN NON-CASH WORKING CAPITAL

| | Year Ended December 31, | |
|---|---|---|
| ($ thousands) | **2009** | 2008 |
| Changes in non-cash working capital items: | | |
| Accounts receivable | **(4,498)** | 943 |
| Prepaid expenses and deposits | **(851)** | 528 |
| Accounts payable and accrued liabilities | **5,820** | 1,515 |
| Cash distributions payable | **831** | 252 |
| Working capital acquired from corporate acquisitions | **(6,681)** | (3,345) |
| Foreign exchange and other | **(999)** | 3,035 |
| | **(6,378)** | 2,928 |
| Changes relating to operating activities | **2,476** | 3,215 |
| Changes relating to financing activities | **831** | 252 |
| Changes relating to investing activities | **(9,685)** | (539) |
| | **(6,378)** | 2,928 |

## 17. SUPPLEMENTAL CASH FLOW INFORMATION

| ($ thousands) | **2009** | 2008 |
|---|---|---|
| Cash interest paid | **3,558** | 4,121 |
| Cash taxes paid | **1,204** | 4,973 |

## 18. SEGMENTED INFORMATION

Zargon's entire operating activities are related to exploration, development and production of oil and natural gas in the geographic regions of Canada and the US.

| | | 2009 | |
|---|---|---|---|
| ($ thousands) | Canada | United States | Combined |
| Petroleum and natural gas revenue | **141,012** | **14,973** | **155,985** |
| Earnings/(losses) before income taxes | **(19,313)** | **5,914** | **(13,399)** |
| Property and equipment, net | **394,448** | **31,516** | **425,964** |
| Total assets | **430,653** | **33,725** | **464,378** |
| Goodwill | **2,969** | **–** | **2,969** |
| Net capital expenditures | **47,682** | **573** | **48,255** |

| | | 2008 | |
|---|---|---|---|
| ($ thousands) | Canada | United States | Combined |
| Petroleum and natural gas revenue | 202,146 | 27,348 | 229,494 |
| Earnings before income taxes | 82,647 | 12,540 | 95,187 |
| Property and equipment, net | 353,174 | 33,572 | 386,746 |
| Total assets | 411,218 | 36,382 | 447,600 |
| Goodwill | 2,969 | – | 2,969 |
| Net capital expenditures | 57,744 | 980 | 58,724 |

## 19. CASH DISTRIBUTIONS

During the year, the Trust declared distributions to the unitholders in the aggregate amount of $45.96 million (2008 – $39.09 million) in accordance with the following schedule:

| 2009 Distributions | Record Date | Distribution Date | Per Trust Unit |
|---|---|---|---|
| January | January 31, 2009 | February 16, 2009 | $0.18 |
| February | February 28, 2009 | March 16, 2009 | $0.18 |
| March | March 31, 2009 | April 15, 2009 | $0.18 |
| April | April 30, 2009 | May 15, 2009 | $0.18 |
| May | May 31, 2009 | June 15, 2009 | $0.18 |
| June | June 30, 2009 | July 15, 2009 | $0.18 |
| July | July 31, 2009 | August 17, 2009 | $0.18 |
| August | August 31, 2009 | September 15, 2009 | $0.18 |
| September | September 30, 2009 | October 15, 2009 | $0.18 |
| October | October 31, 2009 | November 16, 2009 | $0.18 |
| November | November 30, 2009 | December 15, 2009 | $0.18 |
| December | December 31, 2009 | January 15, 2010 | $0.18 |

| 2008 Distributions | Record Date | Distribution Date | Per Trust Unit |
|---|---|---|---|
| January | January 31, 2008 | February 15, 2008 | $0.18 |
| February | February 29, 2008 | March 17, 2008 | $0.18 |
| March | March 31, 2008 | April 15, 2008 | $0.18 |
| April | April 30, 2008 | May 15, 2008 | $0.18 |
| May | May 31, 2008 | June 16, 2008 | $0.18 |
| June | June 30, 2008 | July 15, 2008 | $0.18 |
| July | July 31, 2008 | August 15, 2008 | $0.18 |
| August | August 31, 2008 | September 15, 2008 | $0.18 |
| September | September 30, 2008 | October 15, 2008 | $0.18 |
| October | October 31, 2008 | November 17, 2008 | $0.18 |
| November | November 30, 2008 | December 15, 2008 | $0.18 |
| December | December 31, 2008 | January 15, 2009 | $0.18 |

### 20. RELATED PARTY TRANSACTIONS

Zargon paid $0.05 million (2008 – $0.05 million) for vehicle leases to a company owned by a Board member and $0.41 million (2008 – $0.23 million) for legal services to a law firm of which a Board member is a partner. These payments were in the normal course of operations, were made on commercial terms, and therefore were recorded at their exchange amounts.

### 21. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform with the current year's financial statement presentation.

# CORPORATE INFORMATION

**BOARD OF DIRECTORS**

Craig H. Hansen
*Calgary, Alberta*

K. James Harrison [3] [4]
*Chairman of the Board*
*Oakville, Ontario*

Kyle D. Kitagawa [1] [2]
*Calgary, Alberta*

Geoffrey C. Merritt [2]
*Calgary, Alberta*

Margaret A. McKenzie [1] [3]
*Calgary, Alberta*

Jim Peplinski [2] [4]
*Calgary, Alberta*

J. Graham Weir [1] [2]
*Calgary, Alberta*

Grant A. Zawalsky [3] [4]
*Calgary, Alberta*

**OFFICERS**

Craig H. Hansen
*President and Chief Executive Officer*

Brent C. Heagy
*Executive Vice President and*
*Chief Financial Officer*

Henry J. Baird
*Vice President, Reservoir Engineering*

Jason B. Dranchuk
*Vice President, Finance and Controller*

Tracy L. Howard
*Corporate Secretary*

Brian G. Kergan
*Vice President, Corporate Development and Alberta Plains South*

Mark I. Lake
*Vice President, Geosciences and West Central Alberta*

Kevin C.Y. Lee
*Vice President, Alberta Plains North*

Daniel A. Roulston
*Vice President, Engineering and Williston Basin*

Lorne D. Schwetz
*Vice President, Land*

Al D. Thorsen
*Vice President, Operations*

*(1) Audit Committee*
*(2) Reserves Committee*
*(3) Governance and Nominating Committee*
*(4) Compensation Committee*

**STOCK EXCHANGE LISTING**

Toronto Stock Exchange

Zargon Energy Trust
Trust Units
Trading Symbol: ZAR.UN

Zargon Oil & Gas Ltd.
Exchangeable Shares
Trading Symbol: ZOG.B

**TRANSFER AGENT**

Valiant Trust Company
310, 606 – 4th Street S.W.
Calgary, Alberta T2P 1T1

**BANKERS**

The Toronto Dominion Bank
910, 333 – 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Canadian Imperial Bank of Commerce
9th Floor, Bankers Hall East
855 – 2nd Street S.W.
Calgary, Alberta T2P 2P2

The Bank of Nova Scotia
2000, 700 – 2nd Street S.W.
Calgary, Alberta T2P 2N7

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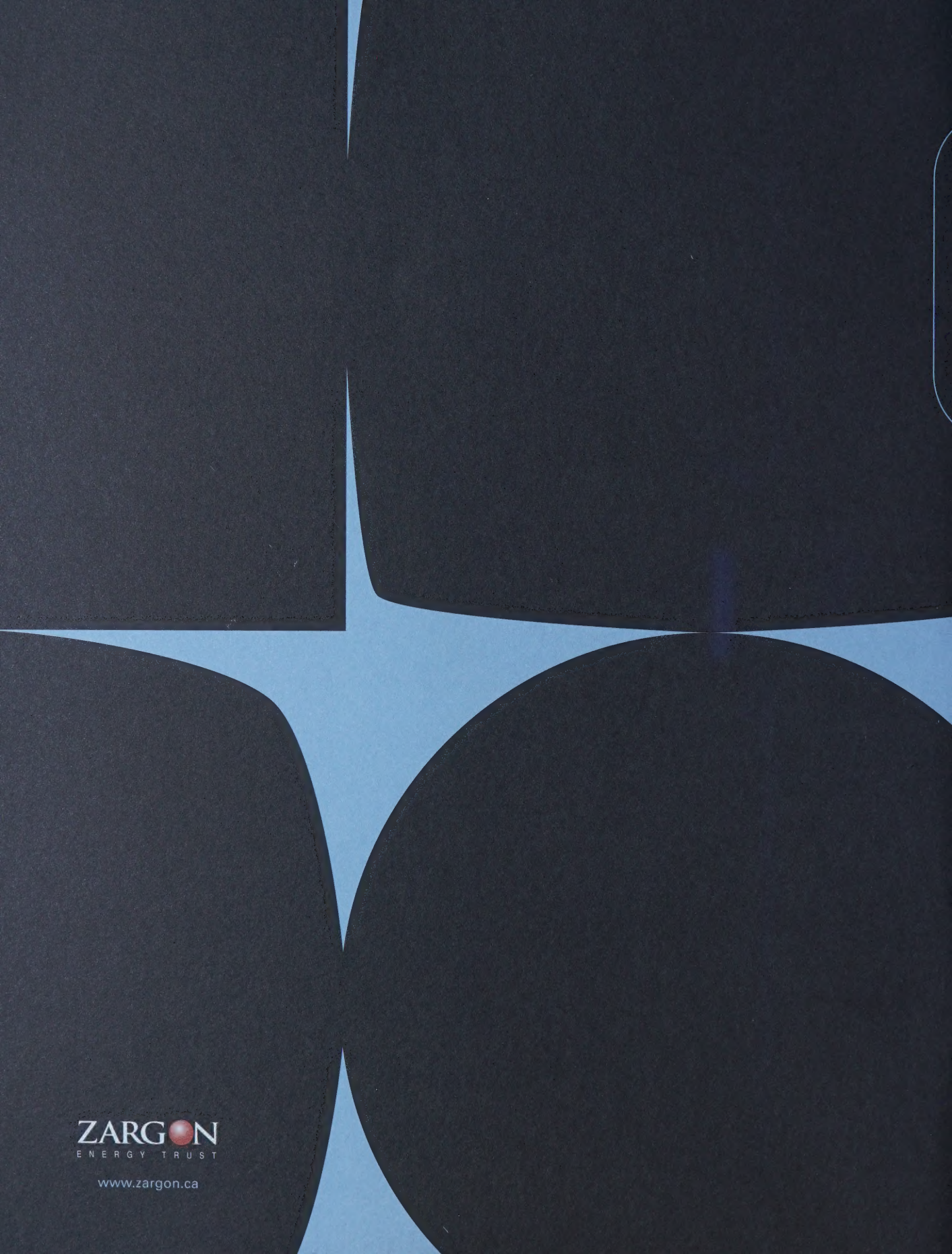
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ENERGY TRUST
www.zargon.ca